BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

VANCOUVER ISLAND ENERGY CORPORATION

(A WHOLLY-OWNED SUBSIDIARY OF
BRITISH COLUMBIA HYDRO AND POWER AUTHORITY)

VANCOUVER ISLAND GENERATION PROJECT

Application for a CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

DECISION

September 8, 2003

Before:

Robert H. Hobbs, Chair
Nadine F. Nicholls, Commissioner

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1.0 INTRODUCTION

1.1 History of the Vancouver Island Generation Project

The Vancouver Island Energy Corporation (VIEC) is a wholly-owned subsidiary of British Columbia Hydro and Power Authority (BC Hydro , the Utility). On March 12, 2003 VIEC applied (the Application) pursuant to Sections 45°and 46 of the Utilities Commission Act (the UCA , Act) for a Certificate of Public Convenience and Necessity (CPCN) for the Vancouver Island Generation Project (VIGP). As counsel for VIEC anticipated at the start of the hearing, the names VIEC and BC Hydro were used more or less interchangeably. This Decision will generally refer to VIEC except where the context indicates BC Hydro.

The Application states that VIGP is BC Hydro s preferred option for securing reliable electricity supply for Vancouver Island and the Gulf Islands. The history of VIEC and VIGP dates back to the mid-1990 s when BC Hydro identified problems with the security and reliability of electricity supply to Vancouver Island. In 1994 the provincial government asked BC Hydro to seek proposals for new resources to meet electricity demand on Vancouver Island. In 1996 the government appointed the Independent Power Producers Review Panel to compare the short-listed proposals with the transmission option preferred by BC Hydro at the time.

Based on that panel s conclusions, the government directed BC Hydro to enter into an agreement to purchase electricity from the proposed Island Cogeneration Project (ICP) near Campbell River. In 1997 the government directed BC Hydro to pursue a second cogeneration plant in Port Alberni, but negotiations with BC Hydro s partners were unsuccessful and Port Alberni s municipal council refused zoning.

VIEC was then incorporated to develop a gas-fired generation project, named VIGP, at another location on Vancouver Island. BC Hydro reviewed potential sites and eventually acquired an industrial site at Duke Point near Nanaimo.

VIGP consists of a combined-cycle natural gas turbine (CCGT) plant with a connection and upgrade to the existing transmission grid and a short on-Island gas pipeline. The environmental, economic, social, heritage and health effects of VIGP have undergone an assessment by the province s Environmental Assessment Office. VIEC stated that its application for an Environmental Assessment Certificate will be referred to the Ministers within 15 days of the Commission Panel s decision on the Application.

During the hearing, VIEC proposed that, in the event the Commission Panel was unable to grant an unconditional CPCN for VIGP, a conditional CPCN be provided. The conditional CPCN would require BC Hydro to undertake a Call for Tenders (CFT) to determine if there is a more cost-effective project or combination of projects to meet its obligation to serve Vancouver Island with reliable and timely supply (T1: 37, 38; Exhibit 4KK).

1.2 Ties to the Georgia Strait Crossing Project

VIGP is closely linked with the proposed Georgia Strait Crossing (GSX) pipeline which would transport natural gas from Sumas, Washington to Vancouver Island. The proposed pipeline is jointly sponsored by BC Hydro and Williams Gas Pipeline Company (Williams).

The portion of the GSX project that is located in the United States received approval from the US Federal Energy Regulatory Commission in September 2002. The Canadian portion of the GSX project was reviewed by a joint panel of the National Energy Board (NEB) and the Canadian Environmental Assessment Agency. The review process included a public hearing in February and March 2003. In its report dated July 2003, the joint panel concluded that, providing that all the commitments, undertakings and panel recommendations are implemented, the project is not likely to result in significant adverse environmental effects. The joint panel recommended that the project proceed to regulatory consideration, where it would be reviewed under the NEB Act.

1.3 The Energy Plan

The UCA provides the British Columbia Utilities Commission (the Commission , BCUC) with broad jurisdiction to consider CPCN applications. As a public utility, BC Hydro must apply to the Commission for a CPCN unless a proposed project receives an exemption from the provincial government.

In November 2002 the provincial government released its energy policy entitled Energy for Our Future: A Plan for BC (the Energy Plan). Policy Action #6 of the Energy Plan states that:

> The Vancouver Island Generation Project will be reviewed by the BC Utilities Commission to determine if it is the most cost-effective means to reliably meet Island power needs.

The Energy Plan provides further context for the review of VIGP. Policy Action #9 requires that electricity distributors acquire new supply on a least-cost basis, with regulatory oversight by the Commission, and Policy Action #13 states that the private sector will develop new electricity generation, with BC Hydro restricted to improvements at existing plants unless it receives the approval of Cabinet to construct a new hydroelectric facility.

In a letter to the Chair and Chief Executive Officer of BC Hydro dated June 25, 2003, the Minister of Energy and Mines stated:

> Accordingly, should a CPCN be granted, please proceed with the orderly development and divestment of both the Vancouver Island Generation Project (VIGP) and Georgia Strait Crossing (GSX) pipeline project, as long as it makes economic and financial sense to do so. (Exhibit 4XX)

1.4 The Hearing

On March 20, 2003 the Commission issued Order No. G-21-03 which established the scope of the review and regulatory process. The Commission held workshops and a pre-hearing conference in Nanaimo on April 22-23, 2003 and then issued Order No. G-30-03 dated April 30, 2003, setting out the regulatory agenda and timetable for an oral hearing of the Application. On May 28, 2003 the Commission sent out a Procedural Information Letter dated May 27, 2003 and a Revised and Updated Issues List for the hearing.

The hearing took place from June 16 to July 3, 2003 in Nanaimo and Vancouver. Approximately 60 intervenors and interested parties participated in the review process, with about 20 intervenors playing an active role in the oral hearing. The VIEC called 19 witnesses in seven witness panels, and intervenors called 22 witnesses.

During the proceeding, Norske Skog Canada Limited (NorskeCanada), Green Island Energy Ltd. (Green Island), Hillsborough Resources Limited (Hillsborough), Maxim Power Corporation (Maxim Power) and Stothert Power Corp. identified other projects to generate electricity on Vancouver Island. Also, Terasen Gas (Vancouver Island) Inc. (TGVI , formerly Centra Gas British Columbia Inc.) submitted an alternative to the GSX pipeline that would expand the existing TGVI pipeline system to and on Vancouver Island to transport gas to VIGP and other gas-fired generation.

After the oral hearing, VIEC and intervenors submitted written arguments and reply. An additional oral hearing day was held July 28, 2003 so that counsel could respond to specific issues identified by the Commission Panel.

1.5 Reliability Requirements

1.5.1 Introduction

BC Hydro states that it needs to invest in new system infrastructure to meet the reliability needs of Vancouver Island and that those needs are dictated primarily by the requirement to meet peak demand. It further states that the compelling factor in meeting this demand is the expected retirement (zero rating) of the High Voltage Direct Current (HVDC) transmission system in 2007 (Exhibit 1, Executive Summary, pp. xii, xiii).

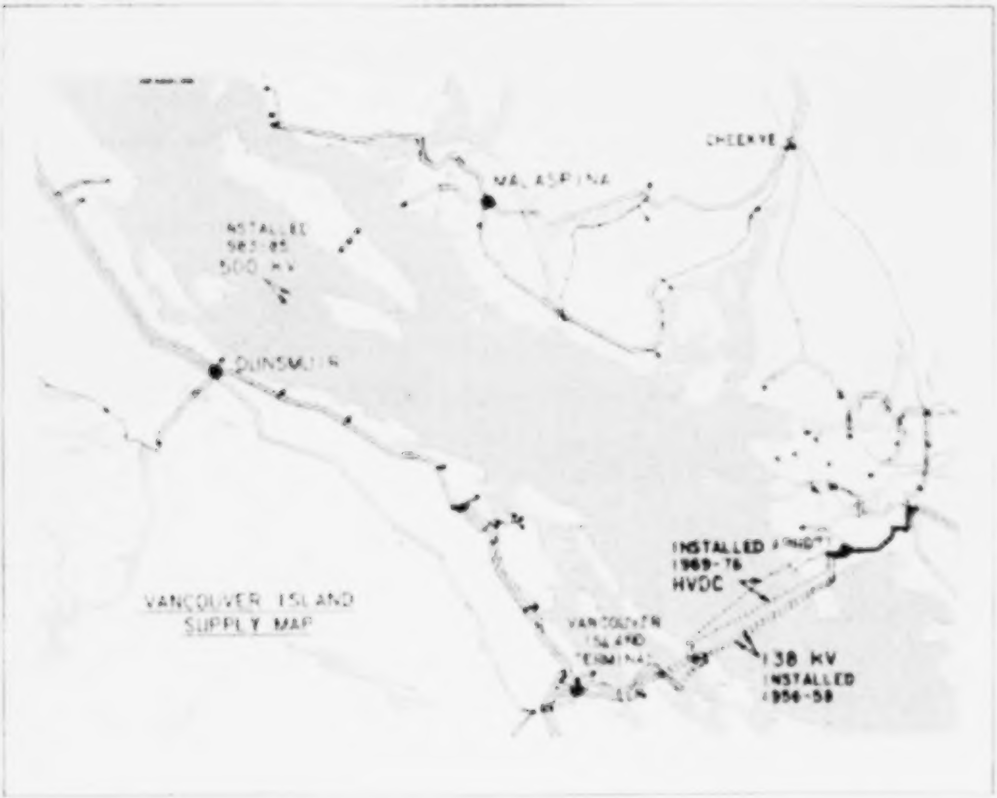
BC Hydro states that other considerations are the need to increase the supply of energy to the system by 2010 and the economic advantages of acquiring that energy before it is needed.

A third factor in BC Hydro s consideration is the operational flexibility that VIGP would provide to deal with multiple facility outages (T4: 788).

Vancouver Island's capacity and energy requirements are being met currently by a number of on-Island generation resources and three transmission systems that connect Vancouver Island to the Mainland. The on-Island generation resources are currently comprised of 450 megawatts (MW) of firm capacity from hydro- electric facilities, 164 MW from the ICP and an assumed amount of 25 MW from new Green Energy and Customer Based Generation (CBG) programs. BC Hydro expects that the dependable capacity from ICP will increase to 240 MW when firm gas transportation for the full fuel requirement of the plant is available. The transmission facilities (shown in Figure 1.1) are comprised of two 500 kV circuits with a dependable capacity rating of 1,300 MW each, two 138 kV circuits rated at zero dependable capacity, and a HVDC system consisting of two poles which together were originally rated at 800 MW but are now rated at 168 MW of dependable capacity. BC Hydro expects that replacement of sections of cables 5 and 9 in 2003 will restore the dependable capacity of the HVDC system to 240 MW until 2007.

Figure 1.1

EXISTING TRANSMISSION CONNECTIONS TO VANCOUVER ISLAND


CHEEKYE
MALASPINA
INSTALLED
500 KV
DUNSMUIR
INSTALLED
1969-76
HVDC
ARNOTT
VANCOUVER ISLAND SUPPLY MAP
VANCOUVER ISLAND TERMINAL
138 KV
INSTALLED
1956-58

(Exhibit 1, p. 25)

1.5.2 Planning Criteria and Operational Criteria

BC Hydro states that it has an obligation to serve its customers in accordance with integrated system reliability standards and that it has adopted the standards defined by the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC).

The WECC has published a number of documents collectively referred to as The WECC Operating and Planning Policies, Procedures and Criteria . The planning standards are found in the WECC document NERC/WECC Planning Standards (revised August 9, 2002) (Exhibit 6, GSXCCC IR 1.3) and prescribe criteria for a system s adequacy and security. Adequacy is the ability of a system to supply the demand and energy requirements of customers, considering scheduled and reasonably expected unscheduled outages. Security defines the system s ability to withstand sudden disturbances.

These standards generally describe the requirements for planning a system such that the system will meet certain minimum performance criteria under various conditions. In the case of planning for system adequacy, one of the main requirements of an interconnected system is that under a single contingency event there shall be no loss of customer load or curtailment of firm load transfers. This is commonly referred to as the N-1 criteria. Under multiple contingencies, load shedding shall be planned and controlled. BC Hydro considers that it is possible to design a load curtailment contract which could be used to meet its planning and operating criteria. Such a load curtailment contract would require the customer to reduce load during periods when BC Hydro is exposed to a violation of N-1 criteria (Exhibit 4FFF).

The planning standards are considered to be mandatory. However, a number of planning practices contained in the standards are suggested as guides and there are no specific sanctions levied for non-compliance with the mandatory planning standards. Nevertheless the planning practices of each utility are examined by the WECC and other utilities and if the system performance is such that other interconnected systems are adversely affected, the WECC will lower the ratings for interconnections so that the impacts are minimized (T4: 974). Reduced ratings could constrain BC Hydro s ability to import or export power.

The publication WECC Minimum Operating Reliability Criteria (August 9, 2002) contains standards for system operation on a real time basis and addresses such issues as scheduling interchanges, operating reserve requirements, operator training, and generation control. Also, the NERC/WECC has a Compliance Enforcement Program that examines utilities compliance with a number of planning and operations policies.

BC Hydro is also a signatory to a compliance program developed by the WECC called the Reliability Management System. This agreement requires BC Hydro to comply with certain reliability criteria pertaining to the operation of the system; failure to do so will result in sanctions in the form of fines or path derating. This agreement and several amendments have been approved for BC Hydro by Commission Orders No. G-73-99, G-72-00, G-8-01, and G-119-01.

1.5.3 Probabilistic Planning

BC Hydro testified that the NERC/WECC standards are largely deterministic in nature but that some consideration is being given to adopting criteria based on probabilistic analysis. BC Hydro performed a number of studies that were used to aid the planning and decision making process. Those studies included the following three reports:

1. Reliability Assessment for Vancouver Island Supply Options December 2001 (Exhibit 4A, BCUC IR°14.4);
2. Probabilistic & Economic Assessment of HVDC Short-term Investment Strategies, June 2002 (Exhibit 4A, BCUC IR 14.4); and
3. Reliability Evaluation of Three Scenarios for Vancouver Island Power Supply —An Expected Energy Not Served (EENS) Study, June 2003 (the EENS Study) (Exhibit 4E, BCUC IR 60.4).

The principal information arising from these studies is the comparison of expected energy not served under various scenarios. The reports are highly dependent on accurate availability statistics for individual components of the electric system.

The Commission has in the past endorsed BC Hydro s compliance with industry standards for reliability as stated by NERC and the WECC, and believes that these standards are necessary for the safe and reliable delivery of power to customers. Moreover, the economic consequences of load shedding other than in exceptional circumstances are not acceptable. The Commission Panel also notes that the probabilistic tools that BC Hydro has developed to aid in comparing various options are very valuable (recognizing that good reliability statistics are necessary to the usefulness of the results) as an addition to the more traditional deterministic criteria. The Commission Panel commends BC Hydro for this work.

1.5.4 Dependable Capacity

In the case of supply to Vancouver Island, the loss of one of the 500 kV lines would be considered to be the maximum single contingency which is not to result in a loss of load. For the loss of two 500 kV lines, load shedding must be planned and controlled. In order to achieve this level of reliability, other system elements must perform to a high level of reliability (Exhibit 1, p. 19). If they cannot achieve these levels the system is derated.

The reliability levels reflect the availability statistics for those elements. In the case of Vancouver Island supply the 500 kV lines have an availability level of approximately 99°percent and the HVDC lines have had varying availability levels ranging from 91.8°percent in the period from 1977 to 1987 and 82.7°percent from 1992 to 2001 (Exhibit 4A, BCUC IR 20.3, Tab C). The ICP had an historical availability of 79.9 percent in its first year of operation (Exhibit 4E, BCUC IR 58.1). For comparison, the Burrard Thermal Generating Station (Burrard) has an availability level of 75 percent for units 1 to 3 and 85 percent for units 4 to 6 (T10: 2170).

BC Hydro rates the dependable capacity of the HVDC system at 240 MW (after repairs to cables 5 and 9), the ICP at 240 MW (with firm fuel supply) and Burrard at 900 MW. BC Hydro states that it requires an availability level of 95 percent for the HVDC lines and 92 percent for IPPs in order to consider them dependable capacity. Transmission lines are considered reliable if they have an availability factor of 98-99 percent. These criteria are not mandated by the NERC/WECC standards and it is apparent that BC Hydro has considerable discretion in determining what it considers to be dependable capacity.

1.5.5 System Performance During N-1 and N-2 Contingency Events on Vancouver Island

An analysis of the significant outage incidents which caused a loss of load for Vancouver Island since 1999 indicates that all five incidents were N-2 contingencies (the loss of two 500 kV lines) (Exhibit 4A, BCUC IR 21.4). However, in three of the incidents an additional amount of load was shed as a result of ICP tripping out for over-frequency caused by the initial load shedding. BC Hydro stated that in those cases load shedding schemes did not operate successfully, and that it is currently developing a computer model to identify possible remedial action schemes to reduce the amount of load loss. However, notwithstanding the amount of load shedding that occurred, it appears that BC Hydro was in compliance with N-1 criteria.

1.5.6 Mitigation of Operational Risks

BC Hydro testified that it is concerned about its operational flexibility to maintain reliable service to Vancouver Island currently and into the future. In particular it is concerned with the reliability of the HVDC system and other operational problems such as low water occurring at inopportune times (T4: 774-778).

BC Hydro has a number of options to mitigate these risks, and must consider the economic impacts of risk mitigation. Some of these options include further repairs to the HVDC system, load curtailment contracts, increased levels of maintenance and more conservative use of on-Island hydro generation. With regard to the ability to contract for load curtailment, the Commission Panel notes that NorskeCanada is prepared to enter into a load curtailment contract to assist BC Hydro meet its peak demand in 2007.

2.0 EXPECTED DEMAND ON VANCOUVER ISLAND

2.1 Introduction

The Application identifies the main driver for new infrastructure to serve Vancouver Island as a supply issue: the expected retirement (zero rating) of the HVDC transmission system. The forecast increase in the demand for electricity on Vancouver Island contributes over time to the need for new infrastructure.

The planned zero rating of the HVDC in 2007 will decrease the dependable transmission capacity to the Island by 240 MW (Exhibit 1, Application, p. 26). VIGP is BC Hydro s preferred option for securing reliable electricity supply for Vancouver Island and the Gulf Islands. If VIGP goes ahead according to the planned in-service date of July 2006, it will provide an additional dependable capacity of 265 MW and a firm annual energy capacity of 2,100 gigawatt hours (GWh). Without VIGP, BC Hydro expects a shortfall in capacity of 213 MW (Exhibit 1, Appendix C).

This Chapter assesses the peak demand on the Island as forecasted by BC Hydro. Chapter 3 evaluates BC Hydro s existing supply for Vancouver Island. Chapter 4 reviews the supply/demand balance and resource requirements for the BC Hydro system.

2.2 BC Hydro's Load Forecasts

The Application relies on BC Hydro s annually updated 20-year Electric Load Forecast, dated December 2002. The BC Hydro forecasts are presented in two versions: without Power Smart and including the impact of Power Smart.

Power Smart is one of BC Hydro s major resource acquisition strategies. Power Smart can be presented as a reduction in the demand forecast or as a component of the supply. However, since Power Smart was ramped down in the 1995-1998 period and was ramped up again in 2001 (T3: 567), there were minimal Power Smart activities until 2002. Therefore, it is more appropriate to use the load forecast before Power Smart instead of with Power Smart when comparing the historical recorded growth rates with the implied growth rates from the BC Hydro forecasts.

Table 2.1 summarizes BC Hydro s forecasts between 2003/04 and 2011/12, the eight-year period which is the focus of the Application:

Table 2.1

SUMMARY OF BC HYDRO LOAD FORECASTS
(before Power Smart)

	2003/04	2007/08	2011/12	Annual Growth
System Energy, GWh	54,462	58,832	63,215	1.9%
Vancouver Island Energy, GWh	10,811	11,568	12,198	1.5%
System Peak Demand, MW	9,745	10,528	11,274	1.8%
Vancouver Island Peak Demand, MW	2,189	2,320	2,438	1.4%

(Exhibit 4D, BCUC IR 24.3)

BC Hydro forecasts that peak demand on Vancouver Island will rise from 2,189 MW in 2003/04 to 2,438 MW in 2011/12. If this forecast is to be realized, the implied average growth rate of 1.4 percent per year will be five times the historical adjusted actual peak demand growth rate of 0.27 percent over 1991/92 to 2001/02 (Exhibit 4, BCUC IR 5.8 Revised). The implied annual peak demand growth rate for Vancouver Island is lower than the forecast for the integrated system, which is projected to grow at 1.8 percent during the same period.

The growth in BC Hydro s forecasts is expected to be due to the residential, commercial and light industrial customer additions because transmission voltage customers are unlikely to provide any load growth in the Vancouver Island coincident peak [Exhibit 4I(b)].

Most of the substantive comments on load forecasting were made by the GSX Concerned Citizens Coalition and Nanaimo Citizens Organizing Committee (collectively GSXCCC). The GSXCCC believes that BC Hydro s forecast model overstates the peak forecasts. Specifically, it argues that VIEC failed to prove that the increase in peak demand will create a gap as large as 213 MW or that VIGP is the only means to meet the gap (GSXCCC Argument, p. 3). GSXCCC's position is supported by three other intervenors: Mairi McLennan, Vic Villeneuve and the David Suzuki Foundation.

2.3 BC Hydro s Forecast Approach and Process

BC Hydro s forecasting approach is based on end-use models instead of time-series models (Exhibit 4, BCUC IR 5.3). In BC Hydro s end-use models, data are collected on a regional basis for a designated base year, being the year for which the most recent history is available (Exhibit 4D, BCUC IRs 24.1, 26.3, 27.1). In the distribution peak model, the calibrated coefficients represent the energy contribution to the peak demand per dwelling or unit.

A time-series model is so called because it is an analysis carried out on data gathered over time. Even though the conditions in the future will not exactly duplicate the past, the model can develop elasticities for different variables from the time-series data. Since peak demand is weather related [40 percent of Island residential customers use electricity as their primary space heating fuel (Exhibit 1, p. 22)], the historical data on consumption of energy has to be standardized in order to isolate the effects of changes in consumption due to the weather. This process is referred to as weather normalization.

Lengthy cross-examinations were conducted by GSXCCC on the weather normalized data. VIEC acknowledged that: It would be better if we showed that actual peak and the weather normalized peak, so that people have that kind of data to work from. We always showed the actual, we didn't show the weather normalized (T3: 626).

The Commission Panel recognizes VIEC's subsequent endeavour to improve the presentation of its weather normalization methodology and results. The Commission Panel disagrees with the argument from the British Columbia Old Age Pensioners' Organization *et al* (BCOAPO) that the revised data were used to retroactively justify a project that might be unnecessary (BCOAPO Argument, p. 4).

The Commission Panel accepts that GSXCCC's concern regarding transparency goes beyond the presentation of results and includes BC Hydro's forecast methodology and input assumptions (T3: 626). The Commission Panel is of the opinion that an understanding of the methodology and knowledge of the quality of input data as well as the effects of the drivers on the modelled results are important to assessing the forecasts. The Commission Panel considers that documents such as extracts from the annual Electric Load Forecast are inadequate as supporting materials, and that issues of lack of transparency apply to several areas, including weather normalization, backcasting, and assumptions that underlie input data.

The Commission Panel expects BC Hydro to include the following components of the load forecast documentation in future CPCN applications for major project additions:

- **a detailed explanation of the appropriateness of the selected forecast methodology compared to other alternative methodologies;**
- **an explicit listing of underlying assumptions and comments on the quality of input data and their sources of information;**
- **intermediate outputs of the modelling process and the verification procedures carried out to validate the modelled coefficients; and**
- **commentary on historical growth trends and implied growth rates and reasons for deviations from trends.**

2.4 Forecast Assumptions and Results

The peak demand forecast in the Application is the product of two variables: stock of electricity-using units and electric intensity per unit of stock (Exhibit 4, BCUC IR 5.3). Stock is the forecast of different types of dwelling units or commercial floor space, and electric intensity is the forecast of electricity input per unit of housing or floor stock.

2.4.1 Power Smart

VIEC s estimates of available on-Island Power Smart resources were derived from the 1991/94 Electricity Conservation Potential Review (1994 CPR). Power Smart was estimated to provide 25 MW for 2003/04, 92 MW for 2007/08 and 102 MW for 2011/12 (Exhibit 1, Appendix C).

The 1994 CPR was updated by the Electricity Conservation Potential Review issued in May 2003. As a result of the new forecast, BC Hydro testified on behalf of VIEC that:

> What we're doing having received or just finalized the conservation potential review is we'll be redoing our plan, and I would imagine that we'll move to that 125 MW. So far the year that's of interest here, prime interest 2007/08 where it currently says 92, I think it would be fair to bump that up by about 20, let s say 112. (T3: 614)

The Commission Panel determines that the updated numbers estimated by BC Hydro should be used when calculating peak demand, resulting in downward adjustments to the peak demand forecast of 20 MW for 2007/08 and 23 MW for 2011/12.

The current ten-year program targets 3,500 GWh of average savings at an overall average levelized cost of $0.020 to $0.025 per kWh. NorskeCanada pointed out that there should be a large incentive to pay more to acquire resources via Power Smart in order to avoid having to build a VIGP in the future given the cost of VIGP (T2: 350). The Commission Panel recognizes that BC Hydro has to balance the demand side management payments as incentives to reduce load with the rate impacts to ratepayers. The Commission Panel expects that BC Hydro will consider the effect of larger incentives when it considers contracted load reductions.

2.4.2 Population Forecast

Population is one of the socioeconomic variables that drives the stock in BC Hydro s demand models. Historically, population on Vancouver Island grew at 1.3 percent per annum between 1992/93 to 2001/02 (Exhibit 4, BCUC IR 5.2). The projected future growth is an increase of 0.96 percent per year over the next ten°years (T2: 391).

One intervenor, Mairi McLennan, expressed doubt over the VIEC projections of population growth and pointed out the very low growth rates in population for the past four consecutive years (Exhibit 31A). Data collected by VIEC showed no growth (0.0°percent) in 1999/00, 0.1°percent growth in 2000/01 and 0.6°percent growth in 2001/02 (Exhibit 4, BCUC IR 5.2). GSXCCC argued that the small increases will continue until the end of the decade with an eventual plateau being reached at growth rates well below those experienced historically (Exhibit 19E, p. 21). In its evidence, GSXCCC provided an analysis of the growth in peak demand based solely on population. This was further refined by the weather normalized data which indicated a peak demand in 2003/04 to 2005/06 that is lower than that of 2001/02 and 2002/03 (Exhibit 19J).

In recognition of the foregoing evidence, the Commission Panel finds that the BC Hydro peak demand forecasts between 2003/04 to 2011/12 should be decreased by the nominal amount of 5 MW to reflect the effects of lower population growth on peak demand in the initial years of the forecast period.

2.4.3 Employment Forecast

Employment is a proxy variable for economic activity on Vancouver Island. Employment on Vancouver Island grew at 1.3 percent annually between 1992/93 to 2001/02 but suffered set backs in terms of negative growth in the last few years. The level of employment in 2001/02 at 295,283 is closer to the 1994/95 level at 296,746 than its peak in 1999/2000 at 317,932 (Exhibit 4, BCUC IR 5.2).

GSXCCC provided evidence that VIEC assumes that employment growth rate on Vancouver Island will be 1.7 percent in 2003/04 over the previous year and that the average annual growth between 2003/04 and 2007/08 will be 2.1 percent per annum (Exhibit 19C, Appendix 2). GSXCCC argued that VIEC s employment assumption is equivalent to a call for an immediate turnaround in previously sluggish Vancouver Island performance. VIEC has not been able to provide evidence or reasons to support the assumption that there will be a drop in the unemployment rate in the short-term (T2: 392).

The Commission Panel concludes that the employment forecast adopted by VIEC is optimistic. This, in turn, may overstate the projections of the stock variable and, depending on which sector is most affected by the low or negative employment growth, this may also lower the electric intensity. Due to the lack of evidence on peak load forecast by industry type, it is unclear by how much the peak demand could be overstated due to VIEC s employment projections.

The Commission Panel considers that VIEC s employment assumptions are likely to overstate the peak load but, due to the lack of information to quantify the effect on the load forecast, will refrain from adjusting the peak demand forecast due to VIEC s employment assumptions.

2.4.4 Peak Design Day

The distribution peak model contains weather sensitive coefficients that are used to measure the change in peak demand per dwelling due to a one degree Celsius drop in temperature below its normal minimum value (Exhibit 4D, BCUC IR 26.6). The design temperature is based on the average of the annual minimum daily temperature for a 30-year fixed period ending in 1994, which is calculated to be -4.4 degrees Celsius for Vancouver Island (Exhibit 4D, BCUC IR 33.1). Evidence shows that if the design temperature is measured for a 20-year rolling average, the design day temperature increases to -3.80 degrees, and if calculated on a 10-year rolling average, the temperature increases to -2.98 degrees (Exhibit 4U). VIEC testified that using the most recent 30-year average would yield a design temperature of -3.7 degrees, but also noted that design temperature is a policy issue as well as a forecast issue and that BC Hydro intends to re-evaluate it this year (T3: 692).

VIEC stated that BC Hydro s previous methodology using 30 to 40 MW of Vancouver Island peak demand for each degree Celsius change in design temperature was too simplistic to accurately model the actual demand change. Nevertheless, VIEC acknowledged that in the Lower Mainland where the design temperature is -6.8 degrees Celsius, BC Hydro uses a crude measurement of approximately 70 MW for a one degree Celsius change (T3: 683).

VIEC acknowledged that warmer than normal temperature would mean lower peak demand. It argues that the 30-year weather series ending in 1994 is an appropriate way to reflect long-term weather trends in its forecast of peak requirements, even though temperatures have been warmer in recent years (VIEC Final Argument, p. 16).

GSXCCC pointed to a growing uncertainty in the peak day demand forecast in the wake of numerous, consecutive warm winters. It stated that more weight should be given to more recent warmer winters so that fewer costly peaking resources would be needed (Exhibit 19 D, BCUC IR 5.1).

The Commission Panel is of the opinion that the chief concern when choosing a design temperature is to strike a balance between avoiding the risk of supply shortfall on the coldest days and that of an over-investment in expensive peak capacity. **For the purpose of load forecasting in the Application, the Commission Panel concludes that the use of -3.7 degrees Celsius based on a current 30-year rolling average is appropriate and determines that peak demand should be reduced by 25 MW. Also, BC Hydro is encouraged to undertake sensitivity studies to review the design temperature for peak planning and to report in future CPCN applications on the demand and energy requirements that result from adjustments to the design temperature.**

2.4.5 Pricing Impacts

Pricing is not a direct input to the BC Hydro model. The model implicitly considers pricing through its calculation of intensity coefficients and projections of stocks that use electricity as the primary fuel for space heating (Exhibit 4D, BCUC IR 26.6). There are three elements to pricing impacts:

- Rate Design;
- Rate Increase; and
- Intensity Coefficients.

Rate Design

VIEC has not carried out any analysis on trailing block rates or other changes to the current rate structure (Exhibit 4D, BCUC IR 34.4). VIEC believes that a stepped rate would not lead to a decrease in the load forecast because it is only designed for transmission customers. It does not expect such a rate will be extended to residential and commercial customers due to logistics (T2: 452, 453). There would be no expected decrease to peak demand because peak demand is driven by residential heating load. The estimated impact of stepped transmission rates is that it could result in a 10 percent impact on energy consumption but not peak demand (T3:°698).

CBT Energy Inc. (CBT) argues that the stepped rate structure is key to the Energy Plan and that VIEC, in the Application, should have looked at the concurrent stepped rate proposed to the Commission and at its effects on the forecast (T1: 125). VIEC could also look into the possibility that BC Hydro would bring forward a time-of-use (TOU) rate and analyze its effects (T1: 129; CBT Argument, p. 8).

TGVI argues that a price signal based on a lower unit cost of gas could result in greater use of natural gas for space heating purposes. TGVI stated that if VIEC were to take into account a stepped rate, the effect would be to decrease the load forecast (T2: 452).

VIEC admits that it is in the interests of BC Hydro s customers to reduce the use of electricity on Vancouver Island for space heating, but cautioned that there is a cost to do so (T2: 450). VIEC suggested that the logistics might be overcome once the new billing platform offers the flexibility (T3: 702).

The Commission Panel finds that stepped rates and TOU rates to non-transmission voltage customers may only be implemented following implementation by transmission voltage customers and, therefore, may not happen with certainty during the initial years of the forecast period. The Commission Panel therefore determines that no adjustments should be made to the peak forecast before 2007/08 as a result of rate design changes. The Commission Panel expects that some form of price signals to a limited set of non-transmission voltage customers will be in place in 2007/08 and will be expanded by 2011/12. The response of consumers to price signals is evidenced by their reaction to the natural gas price increase during 2000 to 2002 (Exhibit 4, BCUC IR 5.4). **On this basis, the Commission Panel determines that downward adjustments of 10 MW in 2007/08 and 20 MW in 2011/12 should be made to the peak demand forecast.**

Rate Increase

The model assumes that electricity rates will rise at the forecast rate of inflation, which is 2 percent per year beginning April 2004 (Exhibit 1, p. 22). VIEC also provided load forecasts that were based on 3 percent and 6.5 percent rate increases in each of the next three years. GSXCCC argues that the 6.5 percent rate increase scenario should be the scenario that is used to measure the capacity shortfall (T3: 623; GSXCCC Argument, p. 4).

The Commission Panel notes that the difference between the 2 percent per year base case and the 3 percent per year rate increase case is only 4 MW in 2007/08 and 10 MW in 2011/12 for Vancouver Island peak demand. The gap increases with the 6.5 percent per year rate increase scenario and the differences become 64 MW and 88 MW in those respective years.

Under the 6.5 percent rate increase scenario, the Vancouver Island energy requirements would be reduced to 10,911 GWh in 2011 by growing at 0.2 percent per annum compared to 0.8 percent per annum in the 3 percent rate increase scenario. The BC Hydro system-wide peak would be reduced to 10,387 MW in 2011, growing at 0.9 percent per annum compared to the 1.3 percent per annum in the 3 percent rate increase scenario. The BC Hydro system energy requirements would be reduced to 56,234 GWh in 2011, growing at only 0.5 percent per annum compared to the 1.1 percent per annum in the 3 percent rate increase scenario (Exhibit 4D, BCUC IR 34.3).

VIEC argues that it is premature to plan for a load forecast based on a rate increase that has not yet been applied for nor been approved (T3: 625). However, any of the three scenarios on electricity pricing: increasing at inflation assumed at 2 percent (base case), at a nominal 3 percent and at a nominal 6.5 percent, would require an application to the Commission for approval.

The Commission Panel accepts the use of 2 percent for the purpose of the Application given the small difference between the 2 percent and the 3 percent scenarios (Exhibit 4D, BCUC IR 34.3.1) and the absence of evidence that would point to a 6.5 percent increase in electricity rates. No adjustments will be made to the peak demand forecast due to rate increase assumptions.

Intensity Coefficients

BC Hydro models customers response to price changes in electricity (own elasticity) as well as price changes in competitive fuels (cross-elasticity). The elasticities contain an assumption that there is a reduced price sensitivity of peak demand during very cold weather. Price elasticity for peak demand is assumed to be 75 percent of the energy demand elasticity (Exhibit 4D, BCUC IR 24.2, p. 11-2).

The customers response to the recent natural gas price hikes is captured in the base year through higher penetration in electricity stock units and intensity of end uses (Exhibit 4D, BCUC IR 32.1). Recent gas price volatility has exacerbated BC Hydro s peak load through higher penetration in the last few years (Exhibit 4D, BCUC IR 25.1).

BC Hydro s model explicitly assumes that future electricity rates will rise at the rate of inflation as of April 2004. Implicit to the BC Hydro model is that the level of electricity consumption, as a product of stock and intensity, has been propelled by seven years of real price decreases that were captured in the base year (Exhibit 4, BCUC IR 5.3; Exhibit 4E, BCUC IR 65.1, p. 2; Exhibit 4S). The residential peak demand model assumes that the intensity coefficients will remain constant for the first 11 years of the forecast period (Exhibit 4D, BCUC IR 30.1; T2: 395).

Shadybrook Farm asked VIEC to compare the regional peak demand calculated from the intensities with the actual published peak (T2: 396). VIEC submitted that there are a number of reasons, among them substation diversity and statistical error, to explain why the actual and predicted substation peaks would differ somewhat (Exhibit 4K).

The information summarized in Exhibit 4K does not fully explain the sources of negative variances of forecasts to adjusted actual peaks (Exhibit 6, Tab GSXCCC IR 1.1 Revised, p. 2). Although the weather effects were isolated and there were no negative effects from electricity rate changes during the years between 1995/96 to 2002/03, there is no explanation of whether the errors were random or were the result of the assumptions on intensities being constant over the next 11 years beyond the base year. The cumulative variances between 1995/96 to 2001/02 result in an overstated forecast of 297 MW over the intervening seven year period. This is an average overstatement of 42 MW annually in the peak demand forecast.

The Commission Panel determines that modest downward adjustments of 7 MW in 2007/08 and 15 MW in 2011/12 should be made to the peak demand forecast to account for the negative variances.

2.5 Adjusted Peak Demand

Table 2.2 summarizes the Commission Panel s determinations in the previous Sections:

Table 2.2

SUMMARY OF ADJUSTMENTS TO BC HYDRO S PEAK DEMAND FORECAST

Vancouver Island Peak Demand, MW

	2003/04	2007/08	2011/12	Annual Growth
Vancouver Island Peak Demand, Table 2.1	2,189	2,320	2,438	1.4 %
Power Smart, Section 2.4.1	(25)	(92)	(102)	
Updated Power Smart, Section 2.4.1	(0)	(20)	(23)	
Population Forecast, Section 2.4.2	(5)	(5)	(5)	
Employment Forecast, Section 2.4.3	(0)	(0)	(0)	
Peak Design Day, Section 2.4.4	(25)	(25)	(25)	
Rate Design, Section 2.4.5	(0)	(10)	(20)	
Rate Increase, Section 2.4.5	(0)	(0)	(0)	
Intensity Coefficients, Section 2.4.5	(0)	(7)	(15)	
Adjusted Peak Demand	**2,134**	**2,161**	**2,248**	**0.7%**

The Commission Panel believes that these results are appropriate for planning purposes to ensure reliable service on the design cold day.

3.0 EXISTING SUPPLY CAPABILITY AND CAPACITY

3.1 Current Situation

BC Hydro s current system-wide energy supply is 58,706 GWh. The firm energy supply of the system located on Vancouver Island is 3,646 GWh. BC Hydro s existing and committed system dependable capacity is 12,599˚MW including system planning reserves of 1,168 MW. For Vancouver Island, the current dependable capacity is 2,180 MW (Exhibit 6, Tab GSXCCC IR 2.2 A&B; Exhibit 4D, BCUC IR 24.4 A&B).

Table 3.1 summarizes VIEC s projection of supply excluding VIGP:

Table 3.1

SUMMARY OF BC HYDRO S EXPECTED SUPPLY CAPABILITY AND CAPACITY

	2003/04	2007/08	2011/12
System Firm Energy Supply, GWh	58,706	63,174	64,642
Supply on Vancouver Island, GWh	3,646	4,325	4,576
System Dependable Capacity, MW	11,431	11,835	11,991
Planning Reserves, MW	1,168	1,193	1,193
Dependable Capacity on Vancouver Island, MW	640	809	818
Firm Transmission to Vancouver Island, MW	1,540	1,300	1,300
Vancouver Island Capacity, MW	2,180	2,107	2,118
Vancouver Island Without Power Smart, MW*	2,154	2,015	2,015

* Supply Capacities for Vancouver Island Without Power Smart were adjusted slightly to align with Exhibit 1, Appendix C.

(Exhibit 4 D, BCUC IR 24.4A, 24.4B Revised)

3.2 Forecast HVDC Deterioration

The expected dependable capacity to Vancouver Island in 2003/04 includes 1,300 MW from the 500 kV transmission and 240 MW from the HVDC transmission. The 138 kV transmission cables are not relied on for planning purposes.

The sudden loss of 240 MW of dependable capacity from the HVDC system in mid-2007 coupled with the load forecast, create VIEC s forecast shortfall of 213 MW in 2007/08 which is central to the Application.

3.3 Expected Supply Additions and Load Reductions

VIEC expects that on-Island generation from existing hydro and the ICP will have no further growth in dependable capacity after 2005/06. The planned supply increase will come in small increments from the Power Smart program, and limited contributions from Green Energy and CBG (Exhibit 1, Appendix C).

VIEC argues that new resource acquisitions such as peak shaving activities (T3: 610) and certain Resource Smart activities (Exhibit 4, BCUC IR 3.8) are time-consuming and expensive (VIEC Final Argument, p. 20). The intervenors generally argue that there is an abundance of resource acquisition opportunities that are more cost-effective than VIGP.

NorskeCanada argues that while there is a significant problem facing Vancouver Island that must be addressed, it does not believe that the problem is so urgent that there is no time to select the lowest-cost reliable solution. NorskeCanada believes that it can offer a contracted demand reduction solution to provide BC Hydro with operational flexibility in the short-term and proposes its energy project suite as a lower cost alternative to VIGP/GSX. NorskeCanada submits that a contracted demand reduction would allow BC Hydro the time to select the lowest cost reliable solution (NorskeCanada Argument, p. 3).

CBT argues that the preferred and best option to solve Vancouver Island s reliability problem is the 230 kV transmission option supported by amongst other things, a load curtailment agreement between BC Hydro and NorskeCanada (CBT Argument, p. 1).

The Joint Industry Electricity Steering Committee (JIESC) argues that there should be load management and peak generation alternatives to meet the power requirements (JIESC Argument, p. 9).

Maxim Power argues that small-scale cogeneration projects (1 MW to 50 MW) would provide lower cost power to BC Hydro than VIGP (Maxim Power Argument, p. 1).

Green Island argues for energy purchases from low cost producers of on-Island generation (Green Island Argument, p. 2). Hillsborough argues that on-Island generation is preferred to off-Island supply (Hillsborough Argument, p. 1).

3.3.1 Contracted Demand Reduction

NorskeCanada offers to reduce the peak load on Vancouver Island by 28 MW through investment in thermomechanical pulp (TMP) energy efficiency and heat recovery improvements, and by 80 MW in winter peak demand management (Exhibit 8, p. 7).

VIEC argues that certain aspects of NorskeCanada s proposal are probably included in the Power Smart load shifting activities (Exhibit 4E, BCUC IR 65.1, p. 5; T3: 710, 711). VIEC further argues that NorskeCanada s reluctance to proceed with CBG and Power Smart could be because it viewed the incentives as insufficient (VIEC Final Argument, p. 56).

The JIESC argues that a program to manage load that includes appropriate compensation to participants should be one element of BC Hydro s plan to meet the electric power requirements on Vancouver Island (JIESC Argument, p. 9).

NorskeCanada takes the position that it can work with BC Hydro to find reasonable mutually beneficial solutions to bridge the near-term capacity constraints. This offer was extended whether or not the ultimate solution includes the NorskeCanada Energy Project (NorkseCanada Argument, p. 3).

The Commission Panel agrees with the analyses of CBT, JIESC and NorskeCanada that BC Hydro should explore load management with its customers to reduce the peaks and defer or negate the need for new facilities. At the same time, a contract with NorskeCanada for load curtailment will involve negotiations with respect to acceptable levels of compensation. Due to the investment cost involved and the issues on the pricing of curtailable energy, the compensation issue should first be mutually resolved by BC Hydro and NorskeCanada (Exhibit 10A, BCUC IR 3.1, IR 4.3). The Commission Panel concludes that no contracted demand reductions should be added to dependable supply for the purpose of the Application. Nevertheless, arrangements with NorskeCanada for short-term load curtailments are an attractive option in the event that BC Hydro needs to bridge a period until a resource like a 230 kV transmission line, other on-Island generation, or even VIGP can be completed.

3.3.2 E-Plus

The E-Plus rate was instituted in 1990 and E-Plus customers have never been called upon to curtail (T3: 711). VIEC argues that only 15 to 30 MW out of the potential 55 MW is estimated to be available if E-Plus customers were called upon to switch to their alternative heating sources. The availability is also conditional upon meeting the tariff s stated objectives that the interruptions will be based on the lack of surplus hydro energy and the unavailability of an alternative from other energy sources (T3: 711-713; VIEC Final Argument, p. 63).

The Commission Panel is aware that the conditions which led to the creation of E-Plus have not existed for many years. If BC Hydro cannot reliably count on E-Plus customers shifting to alternative heating sources at peak times when it will benefit the system, then there may no longer be appropriate conditions to justify the discounted rate offered to E-Plus customers. In that instance, BC Hydro may wish to apply for a phase out of the tariff schedule or to amend the rules for curtailment to ensure customers shift to alternative heat sources when necessary. The Commission would then establish a process to allow E-Plus customers to provide input on the application prior to any determination. BC Hydro may consider this issue as part of its 2004 revenue requirements application.

In the current circumstances the Commission Panel concludes that only 15 MW of capacity reduction should be attributed to E-Plus customers, whether E-Plus is continued or phased out, and determines that a 15 MW upward adjustment should be made to dependable supply.

3.3.3 Peak Shaving

Evidence adduced during the oral hearing shows that BC Hydro has investigated peak shaving measures and is estimating their potential impact (T3: 591). VIEC argues that while BC Hydro has the peak shaving techniques to count on for operating requirements, these techniques are not effective planning options (T8: 1616).

The Commission Panel agrees that these peak shaving measures should not be included until they have been demonstrated to be reliable and normal means for reducing firm peak loads.

3.3.4 Resource Smart

The Application indicated that little or no dependable capacity was expected from the Resource Smart program. VIEC amended the dependable capacity on Vancouver Island that it expects from Resource Smart to 10 MW in 2007/08 and 14 MW by 2008/09 (Exhibit 4, BCUC IR 3.7; Exhibit 4E, BCUC IR 65.1, p. 4; VIEC Final Argument, p. 20).

The Commission Panel accepts VIEC's amendment and concludes that Resource Smart supply additions should be 10 MW in 2007/08 and 14 MW in 2010/11.

As discussed in Chapter 6, further developments at Strathcona and Ladore could add 16 MW and 23 MW respectively to on-Island dependable capacity (Exhibit 4, BCUC IR 3.8).

3.3.5 Green Energy and CBG

VIEC estimates that 25 MW of additional dependable capacity from Green Energy and CBG will be located on Vancouver Island as of 2006/07 (Exhibit 1, Appendix C). The 25 MW is based on the estimated system-wide contribution of 100 MW of dependable capacity from Green Energy and CBG programs, of which 25 MW would be located on the Island (VIEC Final Arguments, p. 22).

BC Hydro, in recent years, has made three separate Request for Proposals (RFP) for Green Energy or CBG:

- April 2000 Green Energy Call - 22 contracts with 20-year electricity purchase agreements (EPA) were awarded. Of the 22, seven hydroelectric and one biogas are on the Island and their aggregate dependable capacity is expected to range between 6 to 8 MW by 2005 (Exhibit 4, BCUC IR 3.4).
- 2002 CBG Call - BC Hydro received six on-Island proposals in April 2003 of which two projects were qualified to enter the call for tender process. No on-Island bid was received (Exhibit 4, BCUC IR 3.9).
- October 2002 Green Energy Call - 17 out of the 70 proposals received were located on Vancouver Island and seven of the 17 are short-listed for the call for tender process (Exhibit 4, BCUC IR 3.4, p. 2). There is an expected aggregate dependable capacity of 28 to 60 MW from these pre-qualified proposals. Neither Green Island nor Hillsborough is included among the short-listed proposals.

Given the 6 to 8 MW of dependable capacity from the 2000 Green Energy Call, VIEC s assumption of 25 MW of on-Island capacity implies that 17 to 19 MW of dependable capacity will be obtained from the 2002 Green Energy Call when the bids are submitted at the end of August 2003 (Exhibit 4E, BCUC IR 55.1).

VIEC submitted that the Green Energy and CBG availabilities are related to the calls for energy rather than calls for capacity; a capacity call would result in a price for capacity in addition to a price for energy (T2: 290, 306). It argues that because Green Energy has limited ability to provide for meeting demand, it is not a substitute for VIGP (VIEC Final Argument, p. 21).

NorskeCanada argues that BC Hydro lacks clarity on exactly what problems it is trying to solve and that BC Hydro has never searched for alternatives to VIGP. The three RFPs conducted to date were not based on today s needs or costs (NorskeCanada Argument, p. 4).

VIEC expects that BC Hydro will obtain 34 to 68 MW of dependable capacity in total from the two Green Energy calls and the CBG call. **The Commission Panel finds that BC Hydro needs to coordinate its supply requirements and resource calls by developing a consistent resource plan. The Commission Panel concludes that the supply additions should be adjusted upwards by 5 MW for 2007/08 and by 15 MW for 2011/12 to reflect the on-going development of Green Energy resources.**

3.4 Adjusted Dependable Capacity

Table 3.2 summarizes the Commission Panel s determinations in the previous Sections:

Table 3.2

SUMMARY OF ADJUSTMENTS TO BC HYDRO S DEPENDABLE CAPACITY

Vancouver Island Capacity, MW

	2003/04	2007/08	2011/12
Existing hydro	449	449	449
Existing purchases	2	2	2
ICP	164	240	240
Green Energy and CBG	0	25	25
500 kV transmission	1,300	1,300	1,300
HVDC transmission	240	0	0
Vancouver Island Without Power Smart*	**2,154**	**2,015**	**2,015**
Contracted Demand Reduction, Section 3.3.1	0	0	0
E-Plus, Section 3.3.2	**15**	**15**	**15**
Peak Shaving, Section 3.3.3	0	0	0
Resource Smart, Section 3.3.4	0	**10**	**14**
Green Energy, Section 3.3.5	0	**5**	**15**
Adjusted Dependable Capacity	**2,169**	**2,045**	**2,059**

* The sum of individual resources may not add to the Vancouver Island Without Power Smart totals from Table 3.1, due to the adjustments made to align Table 3.1 with Exhibit 1, Appendix C.

4.0 SUPPLY/DEMAND BALANCE

4.1 Introduction

This Chapter reviews the extent and urgency of the demand/supply shortfall and the resource requirements for Vancouver Island and the BC Hydro system.

The role of VIGP in the BC Hydro system was summarized succinctly by Ms. Hemmingsen:

> Vancouver Island has an immediate capacity problem. The system has a capacity problem in 2008. By putting the capacity solution on Vancouver Island you solve the system capacity problem in 2008, and then there s an energy requirement pursuant to our forecast in 2010. Which once again the Vancouver Island installation solves some of that. You really have to look at it on a system basis to get a true idea of what the various values are of the option. (T2: 353, 354)

4.2 Vancouver Island Capacity Deficiency in 2007/08

VIEC forecasts that in 2007/08 when the HVDC is planned to be zero-rated, the peak demand (including Power Smart peak reductions) would be at the level of 2,228 MW. BC Hydro estimates that the firm supply capacity would be 2,015 MW, thus creating a deficiency of 213 MW (Exhibit 1, Appendix C).

Table 4.1 summarizes the Vancouver Island capacity deficiency based on the Commission Panel s determinations in the previous two Chapters:

Table 4.1

VANCOUVER ISLAND SUPPLY/DEMAND BALANCE (MW)

	2003/04	2007/08	2011/12
Adjusted Peak Demand	2,134	2,161	2,248
Adjusted Dependable Capacity	2,169	2,045	2,059
Surplus (shortfall)	35	(116)	(189)

4.3 Supply/Demand Balance for the Integrated System

VIEC argues that the VIGP option is consistent with the entire system future capacity and energy needs (VIEC Final Argument, p. 8). According to BC Hydro s forecasts, the system dependable capacity will have a shortfall in 2008/09 of 154 MW (111 MW minus 265 MW) if the VIGP is not in service (Exhibit 6, Tab GSXCCC, IR 2.2A). The Utility s forecasts also show that the system energy will have a shortfall in 2010/2011 of 800 GWh if VIGP (with 2,100 GWh), CCGTs (with 1,500 GWh) and the allowance for market purchases (with 2,500 GWh) are not taken into account (T4: 744).

Without further analysis of BC Hydro s forecasts for its entire system, the Commission Panel notes that the adjustments to the peak demand forecast and planned resources on Vancouver Island would result in the reduction of the system-wide dependable capacity shortfall from 154 MW to 57 MW in 2008/09. This deficiency is small and will likely be further diminished if adjustment factors considered in Chapter 2 are also applied to the system s peak demand forecast and if the rate increases as contemplated by BC Hydro are taken into account.

4.4 New Resources and Resource Planning

VIEC takes the position that as long as some form of solution to capacity problems is required to maintain reliability, VIGP fulfills the necessity criterion of a CPCN (VIEC Reply Argument, p. 3).

VIEC rejects the preference for the new 230 kV transmission line as stated by a number of intervenors. It argues that the new transmission line would require short-term alternatives to bridge the delay and these short-term alternatives, whether load curtailment from NorskeCanada or other additional measures, would increase the net present value (NPV) cost of Portfolio 3 versus Portfolios 1 and 2 (VIEC Reply Argument, p. 10).

A witness for GSXCCC pointed to the importance of Integrated Resource Planning (IRP) activities in providing information to avoid the potential of partial stranding or underutilization of assets, to match demand with a diversity of resources to limit risk exposure, to stage resources to minimize capital expenditure, and to balance supply and demand, amongst other things (T3: 493).

The majority of intervenors accept that there is a need to address a future supply/demand balance problem. While careful analysis of load growth, supply additions and load reductions has narrowed the 213 MW shortfall advanced by VIEC to 116 MW, the problem cannot be entirely resolved without considering other supply alternatives. Intervenors advocated supply alternatives ranging from transmission line expansion to small-scale generation and cogeneration that would allow a better match of supply and demand. The JIESC argues that 618 MW of potential capacity from proposals have been identified during the hearing process (JIESC Argument, p. 10). These proposals are considered in Chapter 6.

The Commission Panel accepts the evidence of BC Hydro that there is a capacity shortfall on Vancouver Island commencing in the winter of 2007/08. Moreover, BC Hydro does not have committed resources, including load curtailment contracts, to meet this capacity shortfall. In Chapter 9 the Commission Panel addresses the issue of Resource Planning and concludes that it is not necessary for the purposes of the CFT process. However, the Commission Panel generally accepts the importance of Resource Planning for other resource additions for Vancouver Island and the system.

5.0 VANCOUVER ISLAND GENERATION PROJECT

This Chapter will assess the schedule, cost and siting for VIGP and the utilization rate and cost of electricity from the facility. As discussed in the following Sections, the Commission Panel recognizes that there is considerable uncertainty in the costs and utilization rate of VIGP. Therefore the Commission Panel has developed a lower cost scenario and a higher cost scenario which cover the likely range of the cost of electricity from the proposed facility.

5.1 Project Description

The proposed VIGP consists of a natural gas-fired electric generating plant, a connection and upgrade to the existing on-Island electric transmission grid, a short gas supply pipeline, a water supply line from the existing Harmac reservoir and a wastewater line to the existing treatment system. The facility would be located in Nanaimo s Duke Point industrial area on Vancouver Island, on a site that was acquired from Pope & Talbot Ltd. (Pope and Talbot) at its Harmac pulp operations. The site is already cleared and is zoned for industrial use.

The VIGP combined-cycle plant design incorporates a General Electric 7FA gas turbine. This is the most mature F class gas turbine manufactured by General Electric. VIEC chose the 7FA model for its proven reliability, rather than the newer, more efficient 7FB model. The combined-cycle system proposed for the plant would have a combustion turbine to produce 170 MW of electricity, a heat recovery steam generator to generate steam from the hot turbine exhaust gases, and a steam turbine to produce 95 MW of electricity. The plant would generate 265 MW of dependable capacity and 2,100 GWh of annual energy. The heat rate of the plant is estimated to be 7.308 terajoules (TJ) per GWh, indicating natural gas consumption of 46.5 TJ per day (Exhibit 1, p. 29; Exhibit 4A, BCUC IR 17.2). Using direct duct firing, the plant could generate 295 MW.

The schedule in the Application showed an in-service date of July 2006, and the facility is expected to have a 25-year life. BC Hydro believes VIGP could have an availability of about 94 percent based on information for single cycle plants, and expects a guaranteed availability of 92 percent if the facility is developed by an Independent Power Producer (IPP) (Exhibit 4E, BCUC IR 58.4; T9: 1941, 1942).

5.2 VIGP Project Schedule

The July 2006 in-service date for VIGP anticipates that engineering and procurement activities for the project will resume in November 2003. To accommodate the proposed CFT, VIEC would move the in-service date to November 2006. Construction and commissioning of the project would need to start two years earlier, in November 2004 (T11: 2282, 2283). This would provide one year for testing to ensure the facility could run at its full dependable capacity level by November 2007, which VIEC identified as the critical date for the replacement supply to Vancouver Island. VIEC testified that one year for testing was standard industry timing. The November 2006 target in-service date would also provide a year in case there are delays or the plant takes longer to construct or commission (T13: 2904).

As the Commission Panel noted in Section 1.1, according to VIEC the application for an Environmental Assessment Certificate for the VIGP will be referred to Ministers within 15 days of the Commission Panel s decision on the Application. In Final Argument, VIEC stated that consultation with the Snuneymuxw First Nations (SFN) by BC Hydro and the provincial government is ongoing. Negotiations have been entered into towards the provision of benefits to the SFN to enhance certainty that the project will be completed. VIEC stated that it included in its cost estimate an allowance for what it thought would be a reasonable accommodation of First Nations (T10: 2169).

In Final Argument, the BCOAPO stated that BC Hydro made an error by accepting directions from the provincial government to proceed with gas-fired generation on Vancouver Island, and a second error by considering that the direction to proceed with the development of a generation project in Port Alberni obliged it to proceed with VIGP. The BCOAPO argued that, even if the Commission were to issue a CPCN, VIGP would not be able to proceed until after a judicial review. As such a review could take several years, BCOAPO argued that VIGP has greater regulatory uncertainty than other proposals.

VIEC replied that BC Hydro is an agent of the provincial government and is not free to ignore the government s wishes. Also, Special Direction Number 8 permits written directives from the Minister who is responsible for BC Hydro.

The Commission Panel considers that issues about the provincial government s directions to BC Hydro relate to the prudency of expenditures made prior to receiving a CPCN. The construction schedule for VIGP should be relatively straightforward, but the Commission Panel notes that, as well as the CPCN, the Environmental Assessment Certificate and agreement with the SFN remain outstanding. However, as the facility should be able to provide a useful addition to electricity supply shortly after it is commissioned and put into service, the project may be able to tolerate more delay than the proposed schedule would indicate.

5.3 VIGP Capital Cost Estimate

VIEC provided P50 and P90 estimates of VIGP capital cost for a June 2006 in-service date, as shown in Table 5.1. (The P50 estimate has a 50 percent probability that the actual cost will not exceed the estimate while the P90 estimate has a 90 percent probability.) VIGP has a firm quotation from General Electric to supply a turbine with a price and delivery time that are fixed until the end of September 2003, and has a verbal undertaking that the date could be extended (Exhibit 4E, IR 53.1; Exhibit 4F, BCUC IRs 69.2, 69.3; T10: 2103, 2149). VIEC stated that ordering the turbine by the end of March 2004 could be sufficient for the 2006 in-service date, depending on how busy the manufacturer is and the amount of delivery time risk that VIEC is prepared to accept (T10: 2152-54).

Table 5.1

VIGP Cost Estimate in Millions of 2002 Dollars

	P50	**P90**
Major equipment	133.3	139.5
Other direct costs	152.1	182.3
Overhead	6.0	6.5
Interest during construction	36.0	41.7
Contingency	12.6	0.0
Total, 2002 dollars	**$340.0**	**$370.0**
Total, as spent dollars		**$386.0**

During the hearing, VIEC confirmed the P50 cost estimate using an updated exchange rate (Exhibits 4FF, 4VV). Delaying the VIGP in-service date to November 2006 to accommodate the CFT would increase interest during construction and other costs by $2 to $2.5 million (Exhibit 4WW).

In Final Argument, VIEC noted that the forecast capital cost is an independent estimate based on the Duke Point site, and that infrastructure at the site has been addressed by the agreement with Pope & Talbot for water supply and wastewater disposal.

In Final Argument, BCOAPO noted that counsel for VIEC objected to questions on whether the Utility would be prepared to limit the exposure of ratepayers to cost over-runs, as was done in the Commission s Decision on the Southern Crossing Pipeline. The BCOAPO also argued that if the P50 number is used for the VIGP, there is a risk that it will compete unfairly with other proposals.

NorskeCanada noted that VIGP cost estimates have increased in the past, and that VIEC does not have turn-key contracts for the project. NorskeCanada recommended that CFT Benchmark costs be based on the current P90 estimate, to give ratepayers the same level of confidence as firm contract bids from IPPs.

In Reply Argument, VIEC stated that the proper place to deal with cost overruns is in a revenue requirements hearing. VIEC also argued that the VIGP benchmark should be the P50 rather than the P90 cost estimate, on the basis that ratepayers are equally likely to benefit from a cost that is lower than the P50 cost estimate as they are to suffer a higher cost.

Some preliminary design work for the VIGP has been completed, the project is based on conventional technology and the site and the steam turbine have been purchased. Nevertheless, the heat recovery steam generator has not been tendered, and the CFT is likely to prevent exercising the firm quotation for the gas turbine and may result in other delays that will increase costs. The need for one year of testing after commissioning indicates that unforeseen costs may materialize, and the contingency allowance in the P50 estimate is only $12.6 million (less than 4 percent). The cost of reaching an accommodation with the SFN is also uncertain. Moreover, while the concept of a P50 estimate should mean that customers are as likely to benefit from cost underruns as to pay for overruns, the certainty of a fixed price bid has value for ratepayers.

For the foregoing reasons, the Commission Panel considers that the actual cost of VIGP is likely to be greater than the P50 estimate. **The Commission Panel finds that a reasonable range for the expected capital cost of VIGP is provided by the P50 and P90 estimates, and concludes that a cost of $340 million in 2002 dollars should be used as the lower estimate and $370 million used as the higher estimate for the project.**

5.4 Prudency of Past Expenditures (Sunk Costs)

5.4.1 Introduction

In determining the best next resource to satisfy the growing electricity demand on Vancouver Island, the Commission Panel is tasked to select the most cost-effective resource to reliably and safely serve BC Hydro ratepayers. Normally projects are compared based on their total cost to ratepayers, which would include past expenditures which are expected to be capitalized and recovered over the life of the new asset. In this case there is the unusual circumstance of a mix of potential projects, some from various project calls, others which would be under individual contracts to supply electricity to BC Hydro, and VIGP (which is an internal project to BC Hydro). The selection process is made even more complicated by the long history of predecessor projects to VIGP that were never built and the very large development costs that have already been spent. These prior expenditures, net of potential future recoveries, are referred to as the sunk costs.

5.4.2 VIEC Position

VIEC restates its rationale for including VIGP/GSX sunk costs in all alternatives at paragraph 83 of its Final Argument.

> *Treatment of Sunk Costs*
>
> 83. BC Hydro included sunk costs in all three portfolios. Doing so neutralizes their influence on the portfolio rankings, which is the identical result that would have been achieved had sunk costs been removed from Portfolios 1 and 2. The latter approach is more consistent with the principle that only future costs matter. Sunk costs were, removed in the requested Portfolios 13, 14 and 15, showing that the ranking does not change.[122] Dr. Pickel reviewed BC Hydro s methodology, and concluded that the sunk costs had been treated equally among the portfolios.

5.4.3 Intervenor Positions

NorskeCanada, in Final Argument, stated that the VIGP Benchmark cost for the CFT should be the current P90 capital cost estimate less expenditures to date. NorskeCanada also argued that BC Hydro s sunk costs should not be added to IPP bids, because:

- the sunk costs are not forward looking;
- other parties sunk costs are not added to BC Hydro s bid; and
- the sunk costs are not necessarily valuable assets since some like the loss on the cancelled turbine will never be recovered.

Hillsborough argued that previously expended funds have no proper role in the analysis and that sunk costs are irrelevant in the analysis and should be ignored.

BCOAPO argued that sunk costs which BC Hydro incurred prior to obtaining a CPCN, were imprudently incurred by BC Hydro and should not be borne either by competing proposals or by BC Hydro s ratepayers.

5.4.4 Commission Panel Determination

The Commission Panel determines that whether or not the VIGP is in the public interest is a fundamentally different question than whether or not the costs to date have been prudently incurred. The Commission Panel notes that all parties who expressed views on the matter appeared to agree that the hearing of the BC Hydro revenue requirements application contemplated for next year would be the appropriate forum for the resolution of the issue of prudently incurred costs. The Commission Panel considers that it would be premature to evaluate the prudency of VIEC s sunk costs prior to a determination of the preferred resource addition for Vancouver Island, and considers this issue is best dealt with in a revenue requirements hearing.

Some proponents of other projects accepted that VIGP should be compared to other alternatives excluding the sunk costs that were incurred prior to this hearing. The Commission Panel accepts these views and will compare VIGP to other options after deducting the sunk costs. VIGP sunk costs are estimated to be $51 million (Exhibit 4FF). **The Commission Panel finds that, after deducting sunk costs, a capital cost estimate of $289 million in 2002 dollars should be used as the lower cost scenario and a cost estimate of $319 million should be used as the higher cost scenario for analyzing the VIGP.**

BC Hydro incorporated its GSX investment in a company separate from the Utility. This implies that BC Hydro intended the GSX pipeline to be operated at arms length from BC Hydro. In addition, the BC Hydro subsidiary entered into agreements with Williams which have created a large liability to the BC Hydro subsidiary if the GSX project or VIGP are not approved. Furthermore, the Commission was not afforded an opportunity to review the contract for transportation service on the GSX pipeline that Powerex entered into. VIEC and the owner of the GSX pipeline are separate entities and the cost of transportation service contracted on GSX is an input cost to VIEC in a similar way that TGVI tolls are an input cost to the ICP plant. **The Commission Panel therefore concludes that the sunk costs of the GSX pipeline are relevant to VIEC for the purposes of the cost of service analysis and the CFT Benchmark set forth in Chapter 9, unless the GSX transportation toll would be expected to be reduced by the GSX sunk costs.**

5.5 VIGP Capital Charges

VIEC assumed that the capital cost of VIGP would be 100 percent debt financed, and amortized over 25 years using a cost of debt of 6 percent (Exhibit 1, p. 81). In revenue requirements calculations, debt and equity costs were treated as level blended payments of principal and interest. Under this approach, depreciation was captured in the principal portion of the blended payment. In Reply Argument, VIEC stated that its cost of capital for this project is 6 percent. The corresponding cost of service, based on the P50 estimate and including sunk costs, is $28 million per year (Exhibit 4FF).

VIEC provided a calculation of capital costs for VIGP if the plant was owned by a fully taxable IPP, assuming a 50/50 debt/equity capital structure, an equity return of 12 percent after tax and debt financing at 7 percent (Exhibit 4E, BCUC IR 63.1). VIEC stated that a 50/50 debt/equity structure is unduly severe for the risk represented by this type of plant. However, notwithstanding that operating costs for VIGP were based on information from IPPs, VIEC was not forthcoming when asked to provide information about typical capital structures for IPP projects (Exhibit 4A, BCUC IR 19.1). During the hearing, VIEC stated that some companies may have sources of financing available to them that would make owning VIGP competitive with BC Hydro s debt/equity ratio and debt and equity costs (T2: 312, 313).

Maxim Power in its filed Evidence provided analyses of cogeneration projects for district heating and greenhouses using an 80/20 debt/equity ratio (Exhibit 27, Tables 5 and 6).

The JIESC argued that the financing of VIGP will effectively absorb some of BC Hydro s equity, and that the cost of this equity should be reflected in the analysis of VIGP. The JIESC recommended the use of 20 percent equity at a return of 15.25 percent.

NorskeCanada argued that normal regulatory practice requires that long-term assets be financed with the weighted average cost of capital of the utility, and that capital dollars cannot be traced and applied to specific projects. NorskeCanada stated that Special Directive Number 4 and Special Direction Number 8 require BC Hydro to maintain an equity component of at least 20 percent, and that in the long run VIGP would require BC Hydro to have equity to support it at least to the extent of 20 percent. NorskeCanada also stated that the rates charged to BC Hydro by an IPP for power from VIGP would reasonably be expected to reflect between 20 and 40 percent equity in the capital structure. NorskeCanada recommended that the CFT Benchmark should, at a minimum, include a cost of capital based on BC Hydro s current average cost of capital.

VIEC did not provide an estimate of the cost of capital for VIGP based on an 80/20 debt/equity ratio. BC°Hydro s Annual Report for the year ended March 31, 2003 states that its return on equity for the 2002/03 fiscal year was 15.47 percent. The Commission Panel estimates that an 80/20 debt/equity ratio and 15.47 percent return on equity for the lower cost estimate of $289 million would result in a levelized capital charge of $28 million per year. The higher cost estimate of $319 million would result in a capital charge of $32 million per year.

An alternative approach would be to consider the cost of VIGP if the facility were developed by an IPP. This approach would not only be consistent with the Energy Plan but would also reflect the intentions of BC Hydro. Although it is possible that lower cost capital may be available, the Commission Panel considers it more likely that an IPP would finance the facility with at least 30 percent equity, and would require payments to recover an after-tax return and debt charges along the lines of the parameters in the Commission staff Information Request (Exhibit 4E, BCUC IR 63.1). The Commission Panel notes that 30 percent equity and a 12 percent after tax return on equity are consistent with the parameters in the application for approval of GSX (T7: 1519, 1520). The corresponding levelized capital charges would be $35 million per year for the lower cost estimate and $39 million per year for the higher cost estimate.

The Commission Panel rejects debt-only financing as impractical for the cost of service analysis, considering BC Hydro s expectations of system renewals. The Commission Panel agrees with NorskeCanada that major capital projects should be considered to be financed at the Utility s weighted average cost of capital. **The Commission Panel concludes that a levelized capital charge of $28 million per year for the lower cost scenario and $32 million per year for the higher cost scenario should be used for VIGP.**

5.6 VIGP Operating Cost

VIEC s estimate of Operating, Maintenance and Administrative (OMA) costs (excluding natural gas fuel costs) can be broken down as follows for 2010/11 (Exhibit 5, NorskeCanada IR 2.1; Exhibit 4FF, Schedule 6):

Table 5.2

VIGP OMA Costs, millions of nominal dollars

	2010/11
Fixed non-major	10
Fixed major maintenance	6
Variable costs	1
Total	**17**

The OMA numbers are estimates from IPPs based on their experience in operating plants similar to VIGP, with a number of site-specific adjustments. The fixed major maintenance OMA cost estimate includes costs under a long-term service agreement offered by General Electric. OMA costs include property taxes that are estimated at $3 million per year.

The Commission Panel accepts VIEC s estimate of OMA costs as set out in Exhibit 4FF and concludes that these costs should be used for VIGP.

5.7 Gas Costs

The largest operating expense is the commodity cost of natural gas fuel, which is a variable expense. Provincial motor fuel tax is charged at 7.0 percent of the commodity cost (Exhibit 1, p. 81).

5.7.1 BC Hydro Gas Price Forecasts

The Application used BC Hydro s reference forecast of gas prices on an annual basis. The forecast was summarized as a levelized gas price of $Cdn 4.80 per gigajoule (GJ) in real 2002 dollars over the 20 year planning horizon, assuming a discount rate of 8 percent real per year. VIEC also evaluated the sensitivity of the portfolio analysis to high and low real levelized gas prices of $Cdn 6.60/GJ and $Cdn 4.10/GJ respectively (Exhibit 1, p. 39; Exhibit 4, BCUC IR 13.1). During the hearing, VIEC provided an updated reference gas price forecast that resulted in a levelized price of $Cdn 4.55/GJ. The lower forecast price resulted from the combined effect of an increase in US gas prices and an increase in the Canadian dollar/US dollar exchange rate (Exhibit 4FF). VIEC did not provide updated high and low gas price forecasts.

One assumption in a scenario proposed by Commission staff used a current Sumas forward price for 2004/05 of $6.07/GJ in nominal dollars ($Cdn 5.80/GJ in real 2002 dollars), and escalated this price at 2 percent per year in real terms. The resulting levelized price was $6.92/GJ (Exhibit 4E, BCUC IR s 56.3 and 56.4). VIEC provided the requested information, but objected to the use of the Commission staff forecast because it was above the highest of the independent forecasts of gas prices that VIEC had surveyed when preparing its November 2002 forecast of gas prices (Exhibit 4E, BCUC IR 63.1, pp. 3, 4).

VIEC in Final Argument noted that its gas price forecast is based on a detailed assessment of market information and data relating to the long-term marginal cost of gas. The forecast is made up of short-term, medium-term and long-term elements. The long-term element is based on proprietary information provided by Confer Consulting Ltd., which relies on both economic theory and estimates of supply and demand for natural gas. The economic basis for the long-term forecast is the long-run marginal cost of new gas supply. This long-run marginal cost is not driven by regional supply factors, but considers all of North America (T9: 1951, 1952).

VIEC distinguished between long-term gas prices and short-term price volatility, and argued that VIGP will be protected against short-term volatility by a supply portfolio risk management strategy. However, BC Hydro acknowledged that it had only recently begun purchasing other than spot gas for the other gas-fired generation that it operates (T9: 1962).

VIEC also argued that its sensitivity analysis showed that VIGP performs well in a high gas price scenario, since efficient CCGTs become more economic relative to other less efficient gas-fired generation as gas commodity prices rise. Dr. Pickel appeared on behalf of VIEC and stated that, although all but 8 percent of new generation in western North America is expected to be gas-fired, some new more efficient units will replace older generation. He felt increases in total gas consumption are unlikely to be large (T8: 1651-54). On the other hand, an excerpt from the US Federal Energy Information Administration January 2003 Energy Outlook projects that natural gas consumption by electricity generators will approximately double between 2001 and 2025 (Exhibit 29C, p. 16, Table 15).

In response to concerns about using CCGTs as a proxy for non-gas resources in light of gas price risk, VIEC acknowledged that economics may favour more non-gas resources in a high gas price scenario. However, it argued that, since future electricity market prices will be significantly influenced by gas-fired generation, its cost of procuring new supply at market value will typically not depend on whether the generation is gas or non-gas. VIEC expects private sector proponents of non-gas resources to competitively bid projects based on the market value of electricity. An exception would be non-gas generation acquired under long-term fixed price contracts, and these contracts have a risk in the event gas (and electricity) prices unexpectedly decrease.

VIEC repeated in Final Argument that gas-fired generation is its preferred source of new electrical capacity and energy on Vancouver Island, and noted that electric generation using natural gas is the principal form of new generation at this time. Natural gas turbines have shorter lead times, lower capital cost, are easier to site near load centres, and have a lower greenhouse gas intensity relative to oil and coal fired thermal plants.

5.7.2 JIESC Position

The JIESC presented Mr. Sheldon Fulton as an expert witness to provide evidence on natural gas prices and price risk. His written evidence noted that gas futures are tradable on the New York Mercantile Exchange (NYMEX) out to 2009, and stated that the price forecast in the Application for 2007/08 understated current gas market prices for that year by 25 percent. This is equivalent to $10/MWh (Exhibit 29C, pp. 3, 25). The JIESC also argued that time of day, day of the week and week of the year cannot be ignored. While high gas prices will favour more efficient gas-fired generation, the JIESC expressed concern that high gas costs will lead to higher electricity prices in absolute terms for customers.

5.7.3 Views of Other Intervenors

Several other intervenors expressed concern that VIEC s forecast understated natural gas prices, and about the effect of higher prices on the cost of power generated by VIGP.

NorskeCanada noted that VIEC s portfolio analysis compared VIGP to quite similar CCGT plants, and ignored other options based on alternative fuels or higher efficiency configurations like the NorskeCanada proposal. For the CFT Benchmark, NorskeCanada recommended using the gas cost assumed in the Commission staff Information Request, as a plausible scenario that is high enough to illustrate the impact of VIGP s higher gas consumption in comparison to other alternatives.

GSXCCC in Final Argument noted that VIEC s analysis did not take into account variations over time in the ratio of gas price to electricity price, or that when both gas and electricity prices rise in tandem, more non-gas-fired generation becomes economic.

5.7.4 Commission Panel Determination

The Commission Panel recognizes the difficulty in forecasting gas prices over the long term. Furthermore, short-term volatility and current high spot prices should not be given undue consideration in the evaluation of long-term generation alternatives like VIGP.

Nevertheless, it is widely observed and broadly accepted that natural gas prices have moved to higher levels since the mid 1990s (Exhibit 19A, p. 7, Figure 1; Exhibit 29C, p. 8, Figure 5). In part, the increase can be attributed to the increase in gas-fired electrical generation. Concerns that supplies of natural gas in North America are being depleted and will need to be supplemented by supplies from remote areas, offshore and non-conventional resources, support the view that gas prices are likely to continue at recent broadly higher price levels. Mr. Engbloom of Confer Consulting Ltd., who appeared on behalf of VIEC, acknowledged that the reliance on conventional producing basins has been heavy, that production in these basins is flattening off, and that gas from other sources will be needed (T9: 1958).

Furthermore, the periods when BC Hydro will need to run VIGP to meet capacity requirements are likely to be times when gas prices are relatively high. Risk management strategies can reduce gas price volatility but may not be able to reduce overall gas costs.

The Commission Panel concludes that gas prices in the future are likely to be higher than VIEC s reference price forecast. The Commission Panel determines that a reasonable lower gas price scenario is provided by VIEC s updated reference price forecast, converted to nominal dollars using a two percent per year inflation rate (Exhibit 4FF, Schedule 1). The Commission Panel determines that VIEC s high case price forecast is a reasonable higher gas price scenario. High case forecast prices in Canadian dollars can be estimated using the currency exchange rates that VIEC was using at the time of the forecast (Exhibit 4E, Figure IR 63.1; Exhibit 4GG, page relating to Table IR 13.1).

5.8 Utilization and Dispatchability

5.8.1 VIEC Evidence

VIGP was submitted to the Environmental Assessment Office and the Commission as a baseload plant, with an annual output of 2,100 GWh per year, which is a utilization rate of approximately 90 percent (T2: 411). During the hearing, VIEC updated its gas and electricity price forecast, calculating a utilization rate of 87 percent and generation of 2,025 GWh per year (Exhibit 4FF, Schedule 6).

Although VIEC expects VIGP to operate at a very high load factor, the plant would be dispatchable. In off-peak periods the plant would not need to generate power if the variable operating cost (principally fuel gas) was greater than the market price of electricity (Exhibit 1, p. 44). VIEC argued that the flexibility of dispatching helps mitigate gas price risk, but also that VIGP s relatively high fuel efficiency will result in a high utilization rate, as its variable operating cost will compare favourably to the market price of electricity.

When the plant is not needed for capacity requirements on Vancouver Island, decisions about whether to run VIGP would be made on a lowest dispatch cost basis using BC Hydro s system simulation model. The model compares the value of stored water in hydro reservoirs (the expected value of the water to generate electricity in the future) to the dispatch cost of VIGP and other thermal resources, and to imports (Exhibit 4A, BCUC IR 14.3; T8: 1701-2; T10: 2106-9). In Final Argument, VIEC defended its position that VIGP would run at a high utilization rate on the basis of simulation modelling which assumed that combined-cycle gas-fired generation will often establish the market price for electricity. VIEC s expert witness, Dr. Pickel, used General Electric s multi-area production simulation model and forecast Lower Mainland gas and electric prices, to predict that VIGP would be dispatched for over 98 percent of the hours that the plant is available (Exhibit 4BB).

5.8.2 Intervenor Views on VIEC Evidence

The JIESC acknowledged that the hydroelectric system could be used to store thermal generation from VIGP, but noted there was a risk that the cost of the thermal generation would not be fully covered by electricity prices in the future.

The JIESC stated that the gas prices for 2006 that were used by Dr. Pickel in his modelling are much lower than current NYMEX gas prices, and argued that low gas prices and high electricity prices result in the projected high utilization factor (JIESC Final Argument, p. 17). The JIESC noted that natural gas prices are inputs to both the General Electric model used by Dr. Pickel and BC Hydro s system simulation model and that no evidence was presented during the hearing as to the forecasting models used by BC Hydro to predict gas and electricity prices.

Other intervenors also questioned whether VIGP would operate as a baseload plant with utilization as high as 90°percent, and noted the effect that lower utilization would have on the unit cost of power from the facility. NorskeCanada argued that VIEC cannot both say that VIGP produces low cost energy based on a high load factor, and also claim the virtue of dispatchability. NorskeCanada recommended 80 percent as a reasonable assumption for a dispatchable plant.

5.8.3 JIESC Evidence

Mr. Fulton, testifying on behalf of the JIESC, stated that the forward market for electricity in the Pacific Northwest indicated that the VIGP would not be able to generate electricity at prices that would cover gas costs for most off-peak hours. Mr. Fulton felt that it is probable that the plant would operate as a peaking facility with a utilization rate of 57 to 60 percent (T10: 2174). Mr. Fulton analyzed the Power Pool of Alberta hourly market, and estimated that gas-fired generation with the heat rate of VIGP would be economically dispatched 54.5 percent of the time (Exhibit 29G, p. 1).

VIEC argued that the Alberta electric market examples used by Mr. Fulton were not relevant to VIGP, as Alberta has a limited transmission connection to the rest of the WECC market, and the hourly pattern is not driven by trade between a hydroelectric area and a gas-fired generating area. The JIESC responded that, as Alberta has the highest concentration of gas-fired generation in the Pacific Northwest, the least-cost supply of short-term gas and a significant transmission inter-connect to British Columbia, it is difficult to understand the argument that the California market is much more relevant than the Alberta market. In Reply Argument, VIEC reiterated that the transmission interconnection and the correlation of Alberta with coastal WECC markets are weak.

Mr. Fulton looked at forward mid-Columbia electricity prices and Sumas gas prices for July 2003 through June 2004. Economically dispatched on an hourly basis, a plant like VIGP would be expected to operate 85.6 percent of the time (T10: 2178-80). This appears to assume 100 percent plant availability. The JIESC disagreed with the characterization in VIEC s Final Argument that Mr. Fulton ascribed an 85.6 percent utilization to VIGP. The JIESC argued that the 85.6 percent utilization calculation was a market indication of utilization rather than Mr. Fulton s modeled value.

Mr. Fulton also used current forward market prices for gas and electricity for 2006 to estimate a utilization rate of 76 percent for VIGP on a block-month basis (Exhibit 29G, p. 6; T10: 2185-87). VIEC criticized Mr. Fulton s calculation of heat rates from forward electricity and gas prices, due to the large bid/ask spreads and the use of regional rather than Lower Mainland prices. VIEC also stated there were differences in the locations that gas and electricity prices were referenced to, and the use of nominal and real dollars, and argued that the Commission Panel should reject the JIESC s utilization rate analysis.

Mr. Fulton used the annual load duration curve for Vancouver Island to estimate that VIGP will need to operate for less than 10 percent of the hours in the year to meet capacity requirements (Exhibit 29C, p. 3). VIEC provided evidence identifying operational factors that would increase the number of hours that VIGP would run to meet reliability needs (Exhibit 4JJ).

5.8.4 Commission Panel Determination

The extensive discussion in the hearing did not assist the Commission Panel in deciding whether VIGP is likely to operate as a baseload plant or a peaking facility. An analytical model that largely uses gas-fired CCGT facilities to forecast the cost of electricity can be expected to predict that VIGP will operate at a high utilization rate. At the same time, forward gas and electricity prices at a particular point in time are likely to have limited usefulness as a means of predicting the relationship between energy prices (and hence the economic heat rate) some years in the future.

As a starting point, the Commission Panel notes that the guaranteed availability of VIGP is expected to be approximately 92 percent. In the first year after its commercial operation date, the ICP had an availability of 79.9 percent and a utilization of 69.5 percent. The lower utilization was attributed to periods of economic dispatch, and there were no outages related to unavailability of gas supply (Exhibit 4E, BCUC IR 58.1 and 58.2). That is, about one-eighth of the availability of ICP was unused because it was not economic to run the plant. VIEC projects that Burrard will produce only 130 GWh in 2003/04, due the higher heat rate (lower efficiency) of that facility (Exhibit 4E, BCUC IR 62.4; T3: 578). This would be a 2 percent utilization rate for Burrard.

VIGP would be a relatively efficient generating plant, but this advantage is likely to decline over the 25-year life of the facility. For example, the next generation of General Electric turbines, the 7FB model, will be more efficient than the unit chosen for VIGP. VIEC acknowledged that the difference in efficiency is significant (T10: 2150, 2151). Moreover, VIGP will also compete with more efficient gas-fired cogeneration facilities, with generation that is not gas-fired and with resources like wind and tidal power that do not have a fuel cost.

All of these factors are likely to cause some erosion of the utilization of VIGP. Furthermore, the utilization rate for VIGP will likely have an inverse relationship to gas prices, so that utilization would likely fall in a higher gas price world. **Therefore, the Commission Panel determines that utilization rates of 80 percent (1857 GWh per year) for a lower gas price scenario and 75 percent (1741 GWh per year) for a higher gas price scenario are reasonable for VIGP.**

5.9 Gas Transportation Costs

5.9.1 GSX Project and Charges

During the hearing, VIEC stated that, if a firm proposal from TGVI showed that the TGVI alternative would be better than the GSX alternative, VIGP and the GSX project would not be integrally linked (T1: 96). Nevertheless, in Final Argument, VIEC stated that it considers the GSX Project to be closely linked to the VIGP, and is its preferred way to move gas to Vancouver Island. At the hearing, VIEC updated the exchange rate used to estimate the cost of the GSX pipeline, calculating a capital cost of $Cdn 296.5 million. Combined with reductions in property taxes and debt financing cost, it updated the estimate of the levelized GSX cost of service to $42 million per year. VIEC proposed that VIGP gas transportation costs from Sumas should be based on half of GSX revenue requirements (Exhibit 1, p. 81; Exhibit 4FF). It argued that there is no justification for a 100 percent allocation of the GSX revenue requirements to VIGP since GSX will also serve ICP and TGVI load growth.

VIEC stated that GSX offers the following benefits that would not be provided by the TGVI proposal to expand its system:

- potential to share the costs with US Mainland shippers;
- higher security and reliability of gas supply to Vancouver Island resulting from construction of a new pipeline system on an independent corridor;

- higher interruptible capacity to supply Island industrial customers;
- no impact on gas transportation to Burrard; and
- lower incremental expansion costs to meet gas load growth on the Island.

TGVI recognized that GSX could be beneficial to its customers, but only if its customers were protected from the unjustified rolling-in of GSX costs and if BC Hydro pays an appropriate rate for on-Island transportation service. TGVI noted that the Powerex agreement for service on the GSX pipeline establishes a fixed tolling methodology but does not set a fixed toll. GSX transportation costs will be subject to actual capital costs and, on an ongoing basis, to risks associated with debt costs, operating costs, foreign exchange rates, inflation and regulatory changes. There is also a risk that in the case of an expansion of GSX, the debt/equity ratio for the pipeline will go from 70/30 to 60/40 (Exhibit 4AA).

5.9.2 TGVI Transportation to VIGP

TGVI proposes to expand its system to provide gas to current and future gas customers on Vancouver Island, including ICP, VIGP, NorskeCanada and other gas-fired generation (Exhibit 12). The expansion to serve VIGP as well as ICP would include pipeline looping, additional compression and a liquefied natural gas storage facility on Vancouver Island. TGVI submitted that its proposal will provide the lowest cost gas transportation to Vancouver Island. Also, it is a staged approach that does not involve investment in facilities until they are necessary.

VIEC submitted rebuttal evidence, including studies by Singleton Associated Engineering Ltd. and Confer Consulting Ltd., that indicated higher costs for TGVI to provide transportation to gas-fired generation on Vancouver Island (Exhibit 4P). In Final Argument, VIEC noted the TGVI proposal is not as mature as the GSX project.

The current TGVI toll for service from Huntingdon/Sumas to the ICP is $1.074/GJ. TGVI expects that this toll would also apply to deliveries to NorskeCanada (Exhibit 13B, BCUC IR 6.1). For the ICP plus VIGP case, TGVI calculated a levelized toll for the 20 years spanning 2003-2023 of $0.946/GJ. The gas utility estimated that a risk adjusted levelized toll would be approximately $1.20 to $1.30/GJ (Exhibit 13C, VIEC IR 11.1). For on-Island service from GSX to VIGP, TGVI estimated a toll of $0.60/GJ (Exhibit 13, BCUC IR 3.3). TGVI estimated the on-Island charge based on a full fixed-variable cost of service methodology using the same principles of rate design as those used by TGVI in its 2002 rate design application (Exhibit 13B, BCUC IR 6.3). Also, VIEC indicated that TGVI had estimated that the cost to build a bypass pipeline from the GSX pipeline to VIGP and ICP would equate to a toll of $0.59/GJ (Exhibit 4E, BCUC IR 63.1). In Final Argument, TGVI referred to both the risk-adjusted toll from Sumas and the on-Island toll as illustrative .

5.9.3 BC Hydro/TGVI Joint Submission

In response to a request from the Commission Panel Chair, BC Hydro and TGVI filed a joint submission on July 14, 2003 comparing the cost of GSX with that of the TGVI proposal. While resolving some differences, the parties did not reach consensus on which transportation proposal is more economic. Table 5.3 summarizes the results for service to ICP and VIGP:

Table 5.3

Present Value Results for Service to ICP and VIGP
(Millions of Dollars)

	BC Hydro View		**TGVI View**	
	GSX	TGVI Proposal	GSX	TGVI Proposal
Present Value with Fuel	442	397	419	303
GSX Sunk Costs	0	55	0	0
Total Cost	**442**	**452**	**419**	**303**
Difference from GSX		**+10**		**-116**

(BC Hydro/TGVI Joint Submission dated July 14, 2003, pp. 7, 9)

The two companies have a generally similar view of GSX costs. TGVI explained the difference between the two views of the cost of its proposal (other than GSX sunk costs) as follows:

- Difference due to facility requirements on TGVI system - $33 million;
- Difference due to impact on the Terasen Gas Inc. Coastal Transmission System - $30 million; and
- Difference due to forecast of compressor fuel - $31 million.

VIEC noted that a difference in depreciation treatment results in a significant difference in undepreciated costs in favour of the GSX project by 2027. BC Hydro estimated an undepreciated cost difference of $74 million, while TGVI estimated the cost difference to be $22 million.

5.9.4 Views of Participants

There was considerable discussion about whether the financial analysis of VIGP should include the cost of incremental TGVI facilities to transport gas to it, or alternatively the TGVI tolls that BC Hydro might pay for the transportation service.

In Final Argument, VIEC stated that the settlement of TGVI tolling issues is beyond the scope of the VIGP proceeding. When estimating the cost of service of VIGP, VIEC felt it was appropriate to make the assumption that 50 percent of GSX charges would apply to VIGP. VIEC stated that this assumption results in a toll that is greater than the charges if GSX costs were rolled in with TGVI costs and less than a layered toll for VIGP.

TGVI maintained that it is not gas facility costs directly that are most relevant to the analysis of the cost of incremental power from VIGP. What TGVI considers most relevant is the rate that BC Hydro/VIEC will pay for gas transportation service on the TGVI system, or alternatively for gas transportation service via GSX plus on-Island service from TGVI. TGVI requested that a CPCN granted to VIEC for VIGP should include a condition requiring VIEC to resolve the uncertainty respecting gas transportation costs to the VIGP. Furthermore, TGVI recommended that the Commission Panel in its Decision should require VIGP to use the transportation alternative with the lowest long-term cost.

VIEC responded that it included all costs associated with service to VIGP, and disagreed with the inclusion of the $0.60/GJ on-Island toll. VIEC argued that TGVI adopted a double standard with respect to expansion costs, and stated that the on-Island toll would be discriminatory and would distort the analysis. VIEC argued that illustrative tolls have little value, and that its cost-based evaluation of alternatives should be used.

NorskeCanada noted that BC Hydro does not provide transmission access free of charge to customers wishing to go against the flow on its electrical transmission system. NorskeCanada proposed that TGVI charges of $0.60/GJ plus annual inflation of one percent should be included in the CFT Benchmark costs for VIGP.

When discussing the Commission s task in its Final Argument, VIEC observed that the courts have found that the responsibility of utility commissions is not to achieve equity among competing private interests, or among competing utilities. Rather, in the case of a distribution utility, it is maximizing the best interests of utility ratepayers. This view was reflected in the comments of counsel at the July 28, 2003 oral proceeding day. Several counsel advised the Commission Panel that its primary concern should be the best interests of BC Hydro ratepayers, and that while it could consider broader public interests such as those of TGVI ratepayers, it should do so with considerable caution (T14: 3007, 3009, 3070, 3075).

5.9.5 Commission Panel Determination

As will be discussed further in Chapter 8, the Commission Panel accepts that VIGP must be evaluated primarily from the perspective of the effect on BC Hydro ratepayers. To do so requires estimates of the costs that are likely to fall to BC Hydro ratepayers. The rates that would apply for transporting gas to VIGP will be determined in other proceedings, and the estimates used in the present analysis are in no way intended to predetermine the outcome of such future proceedings. However, making estimates of these toll charges in order to determine the cost of service of VIGP is necessary since the cost of transporting fuel gas to the plant site is a major cost to the project.

Since VIEC considers that VIGP and GSX are closely linked, and that GSX is the preferred transportation option, it is appropriate to evaluate VIGP on the basis of GSX transportation. The Commission Panel accepts that GSX likely would transport gas for ICP as well as VIGP. **To reflect the GSX tolls that would apply to VIEC for gas transportation service to VIGP, the Commission Panel concludes that 50 percent of GSX charges should be used in the lower cost scenario for the cost of service analysis of VIGP.**

With regard to on-Island charges to transport gas from GSX to VIGP, the Commission Panel considers that TGVI s opposition to rolled-in tolls and the impact of rolled-in tolls on TGVI customers indicates that rolling-in of TGVI and GSX charges is unlikely (Exhibit 13B, BCUC IR 9.6; T6: 1258-63; Exhibit 13H). The Commission Panel finds that on-Island charges of about $0.60/GJ are likely to apply to deliveries to VIGP if the GSX project proceeds. **The Commission Panel finds that TGVI on-Island charges of $0.60/GJ ($10 million per year) for gas transportation to VIGP should be included in the lower cost scenario for VIGP.**

An alternative approach would be to consider the cost impact of VIGP and GSX from a broad BC Hydro perspective, by including the incremental costs for transporting gas to both VIGP and ICP. This is the perspective that VIEC used in its portfolio analysis. Using this approach, BC Hydro would pay all GSX charges until TGVI or some other customer assumes responsibility for a material portion of GSX costs. GSX has no contracts or binding commitments with TGVI.

BC Hydro would also pay a TGVI on-Island toll of about $0.60/GJ to transport 46.5 TJ/d of gas to VIGP and 45 TJ/d to ICP, for a cost of $20 million per year. At the same time, with service available on GSX, BC Hydro would no longer pay a TGVI toll for transportation from Huntingdon/Sumas to ICP. Assuming a

TGVI toll of $1.20/GJ, this is a saving of $20 million per year. That is, there would be approximately zero net change in BC Hydro payments to TGVI.

This alternative approach results in higher gas transportation costs. **The Commission Panel determines that 100 percent of GSX charges and zero net change in TGVI charges should be used as the higher cost scenario for VIGP.**

5.10 Environmental and Siting

5.10.1 B.C. Clean Electricity

The Commission Panel Chair at the beginning of the hearing stated:

> While the Legislature has granted the Commission broad jurisdiction to consider CPCN and applications under the Utilities Commission Act, that jurisdiction is not in (sic) unlimited jurisdiction. Examples of the limits on the Commission s jurisdiction are found in the subject matter of the proceedings before the joint NEB/CEAA panel and before the Environmental Assessment Office. Accordingly, this hearing will avoid areas that are more properly the subject matter of these other reviews.
>
> While the Commission can consider environmental and social impacts, its authority to do so is limited to costs that are likely to emerge as unavoidable costs for utilities and their customers. Therefore, the discussion of environmental and social costs and benefits in this hearing will concentrate on the financial impacts on BC Hydro and its ratepayers.

In a ruling during the hearing, the Commission Panel Chair reiterated that the Commission Panel is not prevented from considering environmental issues, but that its jurisdiction is limited to a consideration of costs that are likely to emerge as an unavoidable cost for BC Hydro ratepayers. Counsel for VIEC agreed that it would be acceptable to question whether VIGP and other projects are within the definition of BC Clean electricity as set out in the Energy Plan, and how VIGP fits within the BC Clean electricity policy (T3: 479, 480).

In Final Argument, BCOAPO referred to the statement of Mr. Justice Goldie where he commented:

> It has been evident for some years now that environmental considerations are important in the formulation of the opinion represented by the phrase public convenience and necessity .
>
> *British Columbia Hydro and Power Authority v. British Columbia Utilities Commission*, (1996) B.C.J. No.°379 (B.C.C.A.) at paragraph 35 (*BC Hydro Court of Appeal* case)

BCOAPO argued that the Commission Panel s consideration of environmental and social impacts needed to include environmental as well as financial costs, in order to comply with the ruling of the British Columbia Court of Appeal. The BCOAPO recognized that a hearing into a CPCN application should not deal in-depth with environmental considerations, and submitted that the BC Clean designation was an appropriate indicator or comparison tool for the broader range of environmental considerations in the VIGP hearing.

The Energy Plan gives the following definition of BC Clean electricity:

> BC Clean electricity refers to alternative energy technologies that result in a net environmental improvement relative to existing energy production. Examples may include small/micro hydro, wind, solar, photovoltaic, geothermal, tidal, wave and biomass energy, as well as cogeneration of heat and power, energy from landfill gas and municipal solid waste, fuel cells and efficiency improvements at existing facilities. This broad definition will allow for the development of a diverse range of cost-effective and environmentally responsible resources across the province.

Policy Action #20 states Electricity distributors will pursue a voluntary goal to acquire 50°percent of new supply from BC Clean electricity over the next 10 years .

BCOAPO summarized the BC Clean status of VIGP and alternatives as follows:

- VIGP is not BC Clean (T2: 469-71);
- The Hillsborough proposal is not BC Clean (T12: 2746);
- The Maxim Power proposal is BC Clean (T13: 2927);
- The Green Island proposal is BC Clean (T13: 2962); and
- For the NorskeCanada proposal, 165 MW or 58 percent is BC Clean (Exhibit 10F).

Based on the BC Clean comparison, BCOAPO argued that VIGP is inferior to competing proposals.

In Final Argument, VIEC stated that BC Hydro plans to meet the 50 percent target through its Power Smart, Resource Smart, Green Energy and CBG programs. It calculated that the resource additions under Portfolios 1, 2 and 3 would be 64 percent, 64 percent and 78 percent BC Clean, respectively (Exhibit 4O).

5.10.2 Greenhouse Gas Emissions

Several intervenors raised the issue of greenhouse gas (GHG) emissions from VIGP, and the contingent liability that BC Hydro may face from possible future GHG emission regulations. VIEC included $2 million in the total net present value costs of Portfolios 1 and 2, as the expected cost of meeting its voluntary commitment to offset 50 percent of the GHG emissions from VIGP through 2010 (T3: 595).

In addition, BC Hydro has developed a \$3/MWh price adjustment for proposals with near-zero GHG emissions that are submitted in response to its Green Energy and CBG programs. VIEC stated that \$3/MWh equates to approximately \$10/tonne CO_2 equivalent, assuming a CCGT GHG emission factor of 0.36 tonnes/MWh. The federal government has stated that it will provide access to GHG offsets at less than \$15 per tonne CO_2 equivalent, and BC Hydro assumed a range of \$5 to \$15 per tonne for greenhouse gas liability (Exhibit 6, GSXCCC IR 8.2 and 8.6). During the hearing, VIEC indicated that its analysis of potential GHG liability for VIGP could be between effectively zero dollars and upwards of \$400 million (T7: 1432).

Dr. Bramley of the Pembina Institute appeared on behalf of GSXCCC. Dr. Bramley identified a plausible scenario of VIGP emission costs ranging from \$2 million per year during 2008-12 to \$64 million per year during 2023-31, with a present value liability over the life of VIGP of \$207 million. He recognized that there are too many policy uncertainties to calculate a precise financial liability to BC Hydro for GHG emissions from VIGP . Nevertheless, Dr. Bramley felt that the financial liability from GHG emissions is an important factor that should be included in any analysis of a full range of options for managing electricity supply (Exhibit 19B, pp. 10, 11). Dr. Bramley stated that the federal government and most experts are broadly in agreement that the most likely expected price of GHG emission offsets is \$10 per tonne (T7: 1380-82).

In Final Argument, GSXCCC suggested that the system-wide requirement for new generation could be met with zero and low GHG generation resources. GSXCCC disagreed with BC Hydro s claim that it is managing its GHG liability risk, particularly past 2010.

GSXCCC acknowledged that natural gas has a lower GHG intensity than other fossil fuels, and is a relatively preferred energy source. However, GSXCCC argued that the cost of VIGP cannot be adequately evaluated without explicit factors for its GHG liability. It acknowledged that the \$3/MWh price adjustment reflects GHG liabilities in relation to Green Energy and CBG projects, but noted that the adjustment had not been applied to VIGP.

The Society Promoting Environmental Conservation (SPEC), other intervenors and several Interested Parties expressed similar concerns about GHG emissions from VIGP.

VIEC argued that potential future GHG liabilities will not preclude the development of CCGT generation. In Reply Argument, it noted there is a range of plausible future scenarios and that it expects the magnitude of future GHG regulatory costs to be nothing like those suggested by Dr. Bramley. It also stated that BC

Hydro s purchases of Green Energy and CBG and associated emission reduction credits are intended to address its future GHG liability. It defended a portfolio approach to GHG risk management as being consistent with industry best practice.

5.10.3 Siting of VIGP

The Application described in some detail the site selection and screening process that VIEC used to select the Duke Point location for VIGP. The objective was to find a site that met engineering and business requirements and offered socio-economic benefits to the community, while minimizing or avoiding adverse impacts to the environment, public health and cultural-heritage values. A long list of potentially suitable candidate sites on Vancouver Island was ultimately narrowed to the selected site. The process included open houses regarding the selection process and identification of the Duke Point site as the preferred location in February 2002 in Cedar and Nanaimo and on Gabriola Island.

The Duke Point site near Pope & Talbot s Harmac Mill scored the highest in VIEC s evaluation of the short-listed sites in large part because of the reduced amount of development and lower environmental impacts that would result from the use of existing water supply and wastewater treatment infrastructure, the short pipeline connection to natural gas supply and the distance from residential areas. The site is located in an existing industrial area and further development of industrial operations at the site is consistent with the official community plan. VIEC has purchased the property, and has an agreement for the supply of water to VIGP and the treatment and discharge of effluent from VIGP (Exhibit 1, pp. 53-62).

A number of local residents submitted Letters of Comment that generally opposed VIGP (Exhibit 26). Several of the Letters of Comment expressed concern about the impact of VIGP on air quality, especially with regard to particulate emissions. Some letters noted the GHG produced by VIGP, and the contribution this would make to global climate change. Many Letters of Comment also were concerned about the cost of power from VIGP, and recommended alternatives that the writers felt would be lower cost, more sustainable and more green .

SPEC in Final Argument noted that VIEC had not included costs associated with re-location of people whose health was adversely affected by VIGP. The Islands Trust opposed VIGP on the basis that VIGP would run counter to its goal to discourage activities or projects that would reduce the natural and aesthetic values of the Local Trust Area.

5.10.4 Commission Panel Determination

The Commission Panel has previously determined the scope of environmental and social matters that are to be considered within the context of the Application. The submissions on behalf of the BCOAPO have not persuaded the Commission Panel it was in error in its earlier determination.

The Commission Panel further observes that the *Environmental Assessment Act* SBC 2002 Chapter 43, (EAA, 2002) provides for an environmental assessment process for reviewable projects as defined by that Act. It prohibits, among other things, the construction of all or part of the facilities of a reviewable project unless the person first obtains an Environmental Assessment Certificate for the project or the executive director has determined that an Environmental Assessment Certificate is not required for the project.

The EAA, 2002 replaced the *Environmental Assessment Act* RSBC 1996 Chapter 119 (EAA, 1996). The latter Act (except for the waste management provisions) came into force on April 21, 1997, which was subsequent to the decision in the *BC Hydro Court of Appeal* case. The UCA does not specifically refer to environmental considerations. The enactment of the EAA, 1996 and its replacement by the EAA, 2002 have served to provide another provincial body with primary responsibility over environmental considerations (other than those that have financial impacts in the determination of public convenience and necessity), especially for reviewable projects.

In the context of the Application, the Commission Panel considers the BC Clean designation is a useful qualitative measure for comparing generation projects. From this comparison, it is evident that VIGP is less desirable from an environmental perspective than several alternative projects. Nevertheless, VIGP would not seem to impede BC Hydro s ability to acquire 50 percent of new supply from BC Clean electricity over the next ten years.

On a more quantitive basis, the Commission Panel considers that the financial analysis of VIGP and alternative projects needs to explicitly recognize potential GHG liability. At the same time, the concerns expressed by Dr. Bramley and VIEC about the uncertainties in calculating this liability appear to be well justified. Also, noting the possible range identified by VIEC, the Commission Panel is concerned that it not assign an unduly high liability figure without solid reasons indicating that such an outcome is likely.

The evidence indicates that a GHG emission offset cost of \$10 per tonne CO_2 equivalent is broadly supported at this time. This represents a cost of about \$3.60/MWh for VIGP (Exhibit 6, GSXCCC IR 8.6). It would also indicate a zero cost for hydroelectric and wind, and a nominal cost for generation fueled with biomass. A typical coal-fired generation plant would have a cost of $10/MWh. Treating potential GHG liability as a cost rather than as a credit for low GHG projects will simplify the comparison of alternatives from a least-cost or cost-effectiveness perspective. Including GHG liability costs in the comparison of alternatives will also address and give reasonable weight to the greenhouse gas emissions concern that several parties raised. **The Commission Panel determines that a GHG emission offset cost of $3.60/MWh in real 2002 dollars should be used in the analysis of VIGP.**

The proposed site for VIGP was selected by a thorough process that included public consultation. The Environmental Assessment Office is responsible for identifying restrictions and mitigation requirements that will apply for the use of the site. **The Commission Panel concludes that, in the context of its review of the Application, the proposed site is suitable for the project.**

5.11 VIGP Cost of Service

The Commission Panel recognizes that there remains considerable uncertainty in the costs of VIGP, especially gas costs, gas transportation tolls and capital costs. The utilization rate for VIGP is also uncertain. Therefore, the Commission Panel has developed two plausible scenarios that cover the likely range of the cost of electricity supply from VIGP. Table 5.4 shows costs for the two scenarios for 2010/11 that are taken from the 25-year cost of service schedules that are attached as Appendix A to the Decision.

Table 5.4

VIGP Cost of Service in 2010/11
(Millions of Nominal Dollars)

	Lower Cost	Higher Cost
Capital charges, Section 5.5	28	32
OMA cost, Section 5.6	17	17
Gas commodity, Section 5.7	72	90
Motor fuel tax, 7% gas commodity	5	6
GSX gas transportation, Section 5.9	23	46
TGVI gas transportation, Section 5.9	10	0
GHG offset cost, Section 5.10	8	7
Total Cost of Service	**163**	**199**
Annual Energy, GWh, Section 5.8	1,857	1,741
Unit Energy Cost, $/MWh	88	114
Unit Energy Cost, 2002 $/MWh	73	96
25-Year Average Cost, 2002 $/MWh	**69**	**103**

The Commission Panel concludes that each scenario is reasonable and that gas prices are too volatile to forecast with certainty. Since BC Hydro ratepayers rather than VIEC will take on the gas price risk and long-term gas costs have not been hedged, the Commission Panel cannot discount the likelihood of the higher cost scenario in Table 5.4.

6.0 ALTERNATIVES TO VIGP

BC Hydro recognizes that it has the responsibility to demonstrate that its selected project, VIGP, is superior to all other alternatives for reliably serving Vancouver Island at the lowest overall cost to all ratepayers. The following alternatives were raised by various participants or BC Hydro as complete or partial solutions for meeting the capacity and energy needs of Vancouver Island.

6.1 Upgraded HVDC

6.1.1 Background

As discussed previously, BC Hydro s assessment of the condition of the present HVDC system from the Arnott Substation to the Vancouver Island Terminal concluded that the present HVDC system will be undependable by the year 2007 and, therefore, would create a capacity shortfall in terms of reliable supply to Vancouver Island.

The HVDC system consists of Pole 1, with a nameplate rating of 312 MW, and Pole 2 with a nameplate rating of 476 MW (Exhibit 4A, BCUC IR 20, Tab A, p. 1). Pole 1 was derated to zero dependable capacity and Pole 2 was derated to 240 MW in 2000. In October 2002, Pole 2 was derated to 168 MW when cables 5 and 9 were determined to be in poor condition (Exhibit 3A). BC Hydro considers that the HVDC system will have a dependable capacity of 240 MW up to 2007 after sections of cables 5 and 9 are replaced (scheduled for 2003). This rating is the half pole rating of Pole 2.

Although the dependable rating of the HVDC system is limited to 240 MW, the system continues to operate and is frequently loaded at much higher levels than the firm rating. For example, prior to the disturbance of December 26, 2002 the HVDC system was loaded to 561 MW and on March 22, 2003 it was loaded to 317 MW (Exhibit 4A, BCUC IR 21.4).

In assessing the end of life for the HVDC system, BC Hydro commissioned a number of reports from consultants and internal BC Hydro experts (Exhibit 4A, BCUC IR 20.3, Tab E). One study concluded that the cables could have a relatively long life span after the repair of damaged cables 5 and 9. However, the component pieces of the HVDC converters had a number of serious deficiencies which the consultants estimated would limit the dependable life of the HVDC system to an additional two to three years (i.e., to 2003/04) without a major replacement program. Alstom T&D Power Electronic Systems (Alstom) suggested that with the replacement of the valves in Pole 2, retirement could be deferred to 2012. BC Hydro concluded that the system could be considered dependable until 2007 without major component replacement but would require an increased maintenance and partial life extension program totalling $32.67 million (Exhibit 4A, BCUC IR 20.2).

BC Hydro testified that the 2007 zero-rating decision was a judgment call and that it was not possible to accurately predict the exact timing when this facility should be retired.

6.1.2 HVDC Life Extension

BC Hydro also examined a full life extension program for Pole 2 which would restore 476 MW of capacity and extend the life of the pole to 2018 at a capital cost of between $27 million (best case scenario) and $67 million (worst case scenario) and additional maintenance (Exhibit 4A, BCUC IR 20.3, Tab C).

This option was subsequently rejected by BC Hydro management because of perceived uncertainty with regard to being able to achieve an acceptable level of availability and because of unmitigated seismic risks of soils liquefaction at Arnott Substation and at an area of cable crossing (Roberts Bank) which could be subject to slope failure (Exhibit 4D, BCUC IR 44.1, Exhibit 4A, BCUC IR 20.3, Tab C). Mr. Elton testified that this decision was made on the basis of a judgment call and that not all of BC Hydro s experts were in agreement with that assessment (T2: 291).

BC Hydro stated that in order to consider the HVDC system dependable it would have to achieve an availability level of 95 percent (Exhibit 4D, BCUC IR 45.1). The historic level of availability for Pole 2 was 91.8 percent in the early years and deteriorated to 82.7 percent from 1992 to 2001, primarily because of a lack of emphasis on restoration and maintenance (Exhibit 4A, BCUC IR 20.3, Tab C; Exhibit 4B, BCUC IR 20.1, Tab C, p. 27).

Alstom suggested BC Hydro could achieve a 95 percent availability level for an additional ten years with a valve replacement program (Exhibit 4B, BCUC IR 20.1, Tab A, Section 6, p. 3).

6.1.3 HVDC Replacement Project

In 1997 BC Hydro examined the possibility of replacing the present HVDC system with new terminal equipment and possibly new cables (Exhibit 4A, BCUC IR 20.3 Tab A; Exhibit 1, p. 34). BC Hydro examined two voltage options at 300 kV and 450 kV. The 450 kV option was rejected as it would have required new undersea cables whereas the 300 kV option could utilize the existing cables. The 300 kV option consisted of two stages of replacement. In the first stage, Pole 3 would replace Pole 1 and provide 540 MW of capacity at an estimated capital cost of $172 million. Similarly, Pole 4 would replace Pole 2 and provide an additional 540 MW of capacity at a capital cost of $213 million.

BC Hydro considers the disadvantages of this option to be seismic risk and an uncertain life span associated with the cables.

6.1.4 Commission Panel Determination

The HVDC system will continue to be a valuable backup and modest investments will maintain its availability for operational flexibility. However, the Commission Panel accepts BC Hydro s assessment that it should not invest nearly $400 million to replace the HVDC system due to the high cost and seismic risk.

6.2 230 kV Transmission Lines

6.2.1 Costs and Capacity

BC Hydro considered a 230 kV AC transmission option that would replace the existing 138 kV lines from Arnott Substation to Vancouver Island. This option proposes a double circuit 230 kV transmission line utilizing the present 138 kV right-of-way. Each circuit would have a capacity of 600 MW. BC Hydro estimated the capital cost of the first stage to be $168 million in 2002 dollars and the cost of the second circuit to be $141 million (Exhibit 1, p. 33). BC Hydro also stated that these estimates have a great deal of uncertainty and could vary by +/- 25 percent (Exhibit 4A, BCUC IR 21.1).

VIEC stated that the first 12 months of line design and cable engineering for the 230 kV line would cost $1.0 to $1.5 million (Exhibit 4DD).

6.2.2 Schedule and Regulatory Hurdles

BC Hydro argues that the earliest in-service date would be 2008 because of lead times needed for regulatory uncertainty (Exhibit 4A, BCUC IR 21.2; VIEC Final Argument p. 23). In the worst case scenario, BC Hydro estimates that regulatory approvals might take 2 to 2.5 years. The uncertainty arises from questions about the jurisdiction and requirements of the Canadian Government, the Environmental Review Commission of the Fraser River Estuary Management Plan, the Islands Trust Act and the BC Environmental Assessment Office (EAO). In addition, BC Hydro argues that there may be extensive public and First Nations consultation requirements. BC Hydro estimates that these reviews could require 1.5 years of study and an additional 0.5 years of hearing. If an EAO process were required BC Hydro argues that this could add an additional 0.5 years. Procurement and installation of the facilities would also take 2 to 2.5 years (Exhibit 4BBB).

6.2.3 Reliability and Flexibility Benefits

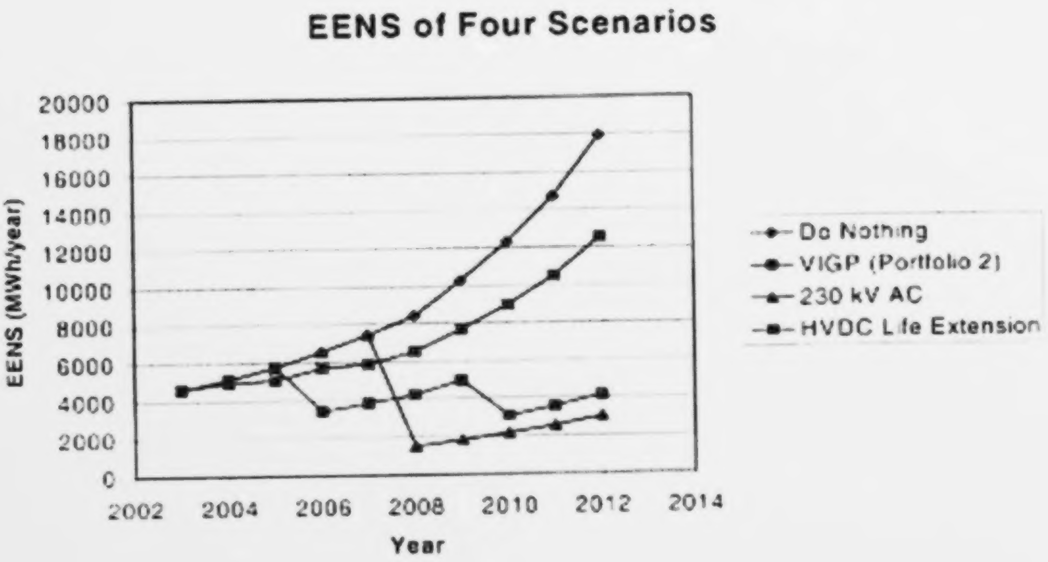
BC Hydro stated that it would seek approval for this option if approvals for VIGP and GSX were denied (Exhibit 6, IR NOCC 2.1; VIEC Final Argument, p. 23). In addition BC Hydro testified that on a technical basis the 230 kV line option is preferred as a first step (T5: 1068). BC Hydro also testified that it had performed a system study comparing the system dynamic performance of two 300 MW CCGTs located on the Island (in addition to the existing ICP) to one 230 kV transmission line and in this scenario the alternatives had a similar performance (Exhibit 4X). Both systems required similar amounts of load shedding under N-2 conditions, but the transmission system had a better frequency response under the 230 kV transmission line scenario. The study also demonstrated that system losses were greater for the two CCGTs scenario than the 230 kV transmission line option.

To compare the relative reliability of various options BC Hydro commissioned the EENS Study to compare the expected energy not served (EENS) from those options (Exhibit 4E, BCUC IR 60.4). The study is a probabilistic assessment of the adequacy of a system to meet load requirements. It was based on a combination of historical outages and failures, assumed repair times and industry data on failure rates for some components such as the CCGTs. The limitations of this study occur because of uncertainty regarding future performance and a lack of historical data for some components.

Four scenarios were compared: a do nothing scenario, VIGP (Portfolio 2), a 230 kV transmission line option (assumed in service in 2008), and a HVDC life extension option. The study shows a gradual increase in EENS (a deterioration in reliability) over the period under both the do nothing and HVDC life extension scenarios. The study indicates that the earliest (2006) significant reduction in EENS would be realized by the

VIGP option. However, the largest overall reduction would be realized by the 230 kV option in 2008. The EENS Study also demonstrates that the partial life extension of the HVDC system contributes an improvement in reliability starting in 2004. The supply to Vancouver Island does not deteriorate significantly or suddenly in 2007 if VIGP is not built. Figure 6.1 reproduces Figure 5 of the EENS Study, and summarizes the results of the study:

Figure 6.1



(Exhibit 4E, BCUC IR 60.4, Figure 5)

6.2.4 Impacts on Mainland Transmission

Under the assumptions of Portfolio 3 which advance the 230 kV line to 2008/09, Revelstoke Unit 5 is advanced to 2008/09 to provide additional system capacity, and a 500 kV line from Nicola to Meridian is advanced by one year.

6.2.5 Commission Panel Determination

The Commission Panel recognizes that the 230 kV line option may be the best reliability reinforcement if on-Island generation becomes prohibitively expensive.

6.3 NorskeCanada Energy Project

6.3.1 Capabilities

As an alternative to VIGP and to meet Vancouver Island needs, NorskeCanada proposes a number of projects and initiatives which could produce up to 364 MW of capacity (the NorskeCanada Energy Project , Project Suite). The Project Suite includes 256 MW from gas and steam turbine generators located at the Crofton, Elk Falls and Port Alberni pulp and paper mills, 28 MW from TMP efficiency improvements at Elk Falls, and 80 MW from load management programs (Exhibit 8, p. 2). The energy estimated to be delivered from the generation is 2,300°GWh/year at a 96 percent load factor.

NorskeCanada states that portions of the Project Suite could be completed in as short as 12 to 18 months and that the Project Suite has the flexibility to meet the demand requirements of Vancouver Island in 2007 (Exhibit 10B, IR 5.1). NorskeCanada states that the reliability of the cogeneration facilities will be in the 98°percent range and that the availability of the combination of facilities should exceed 96 percent (Exhibit 8, p.°15).

6.3.2 Benefits of the NorskeCanada Energy Project

NorskeCanada claims that its proposed Project Suite has a number of inherent benefits over VIGP including lower cost, environmental and social benefits, flexibility to phase in projects to meet load growth and replacement of lost capacity. Also, the projects will not require the GSX pipeline (Exhibits 8, p. 9; T12: 2674).

Cost savings are expected to arise as a result of better fuel efficiencies from a cogeneration facility, and the avoidance of the GSX pipeline by utilizing TGVI s existing facilities. Environmental and social benefits will be realized from lower GHG emissions and the elimination of the GSX pipeline, while creating construction and employment opportunities in three communities.

The Project Suite has the flexibility of being brought on in stages. However, NorskeCanada states that it prefers the projects to be implemented in the following order:

1. Elk Falls, consisting of a first gas turbine, steam turbine, TMP, and demand management for a total of 166 MW. The TMP is dependant on the installation of the steam turbine and the demand management is dependant on the TMP;

2. Crofton, consisting of a first gas turbine and a steam turbine for a total of 61 MW;

3. Port Alberni, consisting of a gas turbine for 45 MW;
4. Crofton with a second gas turbine for 46 MW; and
5. Elk Falls with a second gas turbine for 46 MW.

(Exhibit 10B, IR 9.6)

6.3.3 Costs

NorskeCanada s estimate of capital costs of $450 million for these projects has been broken down as follows:

- Crofton power generation - $123 million;
- Elk Falls power generation - $127 million;
- Port Alberni power generation - $55 million;
- Elk Falls TMP facilities - $131million; and
- Demand Management - $14 million.

(Exhibit 8, p. 19)

NorskeCanada estimates that the proposal would require 52 TJ of gas per day and an additional 31 TJ/day of pipeline capacity from TGVI. The TGVI capacity is proposed to be curtailable as NorskeCanada plans to incorporate distillate capability in most of its gas turbines.

NorskeCanada states that it is confident it could agree on a price for electricity with BC Hydro that is lower than the full cost of VIGP and GSX (Exhibit 8, p. 30).

NorskeCanada s proposal assumes that BC Hydro would assume the gas price risk and that the additional capacity on TGVI would require a toll of $1.13/GJ (Exhibit 8 p. 20; Exhibit 10A, IR 1.5).

6.3.4 Timing and Regulatory Requirements

NorskeCanada states that regulatory requirements would include local or municipal development permits and emissions permits from the Ministry of Water, Land and Air Protection, but it was unable to estimate a time frame for the issuance of these permits. The company also anticipates seeking an Environmental Assessment Certificate from the EAO (Exhibit 10C, IR 1.9). NorskeCanada states that, assuming a start date of January 1, 2004, all projects could be completed by July 5, 2006, and it is willing to assume completion schedule and construction cost risks (Exhibit 8B, Appendix C; Exhibit 10C, IRs 3.12, 3.13).

6.3.5 Commission Panel Determination

The Commission Panel views NorskeCanada s proposal as promising and considers that it has the potential to produce a lower cost alternative to VIGP. However, the Commission Panel recognizes that this proposal has arisen recently and will require significant work between BC Hydro and NorskeCanada to finalize their respective positions.

6.4 Green Island Energy Ltd.

Green Island proposes a supply side project that would be able to deliver 105 MW of firm capacity. The project will produce 105 MW from steam generators fuelled by biomass, will be developed in two stages (45 MW and 60 MW) and will utilize the former Bowater Mill at Gold River. The project is well developed and is expected to be in service by the end of 2004 (Exhibit 17, p. 1). Green Island states that it is prepared to sell the output of the plant to BC Hydro under similar commercial terms to BC Hydro s recent CBG and Green Energy calls. This includes a base price of $55/MWh plus a $2.10/MWh locational credit and $3.00/MWh greenhouse gas credit. However, Green Island would retain any green credits (Exhibit 17, p. 3). Green Island also states that if BC Hydro did not purchase the power it would utilize the open access provisions of BC Hydro s Wholesale Transmission Service (WTS) tariff to sell to other buyers (T13: 2977).

The Commission Panel notes that in the event Green Island uses the WTS tariff, this may alleviate some capacity shortfalls. However, for firm capacity benefits to be realized, BC Hydro needs to have the ability to dispatch the plant when required. Consequently, it would be beneficial for BC Hydro to purchase the output of this plant. Considering that the cost of power from the plant is being offered at $60.10/MWh (which is much less than VIGP and is in line with the last Green Energy call), it would appear that this is an excellent opportunity for BC Hydro to contract with Green Island. Also, this generation resource could make an early contribution to improved operational reliability for Vancouver Island.

6.5 Hillsborough Resources Ltd. (Quinsam Coal)

Hillsborough proposes a coal-fired steam turbine generator to be located at the Quinsam Coal Mine, 27 km southwest of Campbell River. The project would use refuse coal to generate 60 MW of firm electricity. Hillsborough estimates the capital cost to develop the project is $68 million and operating costs would be less than $33/MW. Future fuel costs for new coal delivered to the plant are expected to be approximately $1.00/GJ (Exhibit 16, p. 5, 6). Hillsborough proposes to buy an existing plant in Illinois, USA and move it to Canada. It estimates that the project could take 14 months to complete (Exhibit 16A, IR 5). Hillsborough states that the project is reviewable under the Environmental Assessment Act and the proponents have been in discussions with provincial government officials who have advised them that permitting of the plant would take approximately six months. However, Hillsborough acknowledges that the timing is uncertain (Exhibit 16A, IR 4).

Additionally, the Comox-Strathcona Regional District has passed a no utilities by-law causing Hillsborough to attempt to have the Regional District boundary redrawn so that the facility would come within the City of Campbell River. VIEC argued that this change could take a year to implement. VIEC also stated that transmission upgrades will be required if significant new generation is added north of Dunsmuir Substation near Qualicum.

The Commission Panel believes this project may have promising economic advantages providing environmental permits can be obtained and the issue with the Regional District can be resolved.

6.6 Maxim Power Corporation

Maxim Power identifies a number of potential opportunities for small scale cogeneration projects. The potential sites include the University of BC, Simon Fraser University, and University of Victoria as well as numerous greenhouses, hospitals and industrial sites. The total identified potential for British Columbia is 370 MW (Exhibit 27, p. 8) with less than 50 MW located on Vancouver Island (T13: 2930, 2931). No specific sites were identified as being under development on Vancouver Island at the present time. Maxim Power states that the major hurdle for cogenerators to bid on previous BC Hydro calls for proposals was BC Hydro s requirement that the proponents assume the gas price risk. Maxim Power believes that more viable projects will now emerge as a result of BC Hydro s willingness to accept the gas price risk for new projects as set out in BC Hydro s proposed CFT (T13: 2929).

The Commission Panel believes that, with BC Hydro s willingness to accept the gas price risk and given the inherent efficiencies from cogeneration and the possible green benefits from the secondary use of CO_2 (e.g., in greenhouses), a number of projects may become viable. However, the Commission Panel recognizes that much work will have to be done to identify and develop specific projects.

6.7 Resource Smart (Strathcona and Ladore)

BC Hydro identified a number of Resource Smart opportunities on Vancouver Island. These opportunities include the installation of a third unit at Strathcona which could produce a dependable capacity of 16 MW at a cost of $23 million, a third unit at Ladore which could produce a dependable capacity of 23 MW at a cost of $18 million, a second power plant at John Hart which could produce a dependable capacity of 138 MW at a cost of $210 million, and an additional unit at Puntledge with no defined dependable capacity for a cost of $11 million.

Of these projects BC Hydro considers only Strathcona and Ladore to be feasible as John Hart and Puntledge have significant stream flow impacts. All projects were considerably more expensive to bring on line than BC Hydro s next lowest cost resource which is Revelstoke Unit 5 that could produce 500 MW for $102°million (Exhibit 1, p. 36).

The Commission Panel notes that Strathcona and Ladore would be considerably more expensive than Revelstoke Unit 5 on a unit of capacity basis. Nevertheless, they provide other options for meeting relatively small capacity shortfalls on Vancouver Island.

7.0 PORTFOLIO ANALYSIS

7.1 Introduction

According to Chapter°3 of the Application, BC Hydro determines the most cost-effective means of meeting future system load requirements by building and analyzing 20-year model resource portfolios, utilizing its reliability planning criteria to determine the timing of needed resources. The economic costs and in-service lead times of alternative portfolios are developed, the costs of producing energy are discounted to today s dollars, and the present values of the costs are then compared to isolate the choices. In addition to the scheduling of resources based on these criteria, energy resources may be advanced if doing so reduces the net present value of future costs. The NPV model is proprietary and contains sensitive commercial information that BC Hydro considers to be confidential (Exhibit 4E, BCUC IR 62.1).

BC Hydro identified three basic resource strategies for meeting the Vancouver Island supply shortfall from both a system perspective and a Vancouver Island regional perspective: new on-Island generation, new transmission, and more aggressive load curtailment. A number of resource options were reviewed but not incorporated into the portfolio models for various reasons, but mainly because BC Hydro did not consider that they could supply sufficient dependable winter capacity, that the projects were not sufficiently advanced, or that they could not be considered to be long-term solutions.

BC Hydro expects future electricity to be priced based on the opportunity value of gas-fired CCGTs, and a generic 250 MW CCGT located near Kelly Lake is assumed by the portfolio model to be the proxy resource for all competitive generation. Natural gas price forecasts at the Sumas trading hub are used to estimate the fuel cost of gas-fired generation, including Burrard and VIGP, and to forecast wholesale electricity prices. Prices in the portfolio analysis beyond the forecast period are assumed to stay constant in real terms.

The Application presents three resource portfolios as being feasible alternatives:

- Portfolio 1, VIGP;
- Portfolio 2, On-Island CCGTs; and
- Portfolio 3, Mainland Generation.

The three portfolios provide a trade-off analysis of the economic costs and benefits of advancing new on-Island generation resources to address both the expected 2007 capacity shortfall on Vancouver Island and the longer term system requirements against the timing of new transmission and Mainland generation resources (Exhibit 4, BCUC IR 11.3). The portfolio analyses include the revenue requirements for all expansion facilities that are anticipated to be required to deliver gas to Vancouver Island, whether constructed by TGVI, Terasen Gas Inc., or GSX. This includes facilities to meet all anticipated growth in Vancouver Island gas demands, including TGVI core load growth and gas-fired electric generation (Exhibit 4E, BCUC IR 62.2).

The NPV analysis for each portfolio includes a Perpetuity Adjustment.

For annual cost elements, the Perpetuity Adjustment formula is: $(A/r) \quad (1 + r)^N$ where

A = annual payment in the last year of the study (year 20 for the portfolio analysis)

r = discount rate

N = number of years (20 for the portfolio analysis)

For capital cost elements, the formula is: $P \times 1/((1 + r)^n - 1)$ where

P = NPV of the capital cost of that element

r = discount rate

n = project life

(Exhibit 4E, BCUC IR 62.3)

The energy and capacity contributions from the existing system (BC Hydro resources and long-term purchase contracts) and committed new resources are consistent across all three portfolios. The portfolios all have a number of common elements, including additional units at Revelstoke and Mica and Interior to Lower Mainland 500 kV transmission reinforcement, although each portfolio requires different in-service dates for these projects. Portfolios 1 and 2 include the GSX project, the cost of which includes the annual revenue requirement to service ICP and VIGP, future TGVI load growth and, in Portfolio 2, future on-Island CCGTs. Portfolio 3 includes the estimated cost of upgrading the TGVI system to service ICP and future TGVI load growth.

7.2 BC Hydro Portfolios for Vancouver Island

7.2.1 Portfolio 1, VIGP

Portfolio 1 is used as the reference case and consists of VIGP followed by a new 230 kV transmission line to Vancouver Island in 2010. Power generated by the plant will be supplied to the BC Hydro grid at Duke Point. Natural gas will be provided from the GSX project, via the TGVI system. The project has an expected in-service date of July 2006, a 25-year life, a total cost of $340 million in 2002 dollars including overhead, interest during construction and contingency. If VIGP proceeds as proposed, it would provide dependable capacity of 265 MW and a firm annual energy capability of 2,100 GWh. The Application states that the total net present value cost of this portfolio is $9,677 million (Exhibit 1, p. 42).

7.2.2 Portfolio 2, On-Island CCGTs

Portfolio 2 includes VIGP, followed by further 250 MW CCGTs on Vancouver Island in 2010 and 2016 to meet the expected need for additional dependable capacity and energy. The total net present value cost is $9,525 million.

7.2.3 Portfolio 3, Mainland Generation

Portfolio 3 relies on a new 230 kV transmission line to Vancouver Island in 2008, with a second 230 kV circuit in 2018. It includes the estimated cost of TGVI upgrades required to realize the ICP s full 240 MW capacity, but does not include the cost of mitigating the risk of a capacity shortfall in the winter of 2007/08. The system dependable capacity requirement is met with Revelstoke Unit 5 (a capacity-only addition) in 2008, thereby deferring new system energy capability until 2010 (represented by a CCGT at Kelly Lake). The total net present value cost is $9,687 million, including sunk costs for the GSX project and VIGP.

7.3 Portfolio Analysis Results

In the Application, in response to Information Requests and during the hearing, VIEC provided the following portfolio analysis results to test a number of sensitivities and scenarios.

7.3.1 Application Scenarios and Lower Load Forecast

VIEC analyzed Portfolios 1, 2 and 3 in Chapter 5 of the Application. It also provided the results of modelling a lower load forecast that was developed assuming a 6.5 percent annual rate increase for three years (Exhibit 4, BCUC IR 6.1, p. 7). Using Portfolio 1 (VIGP) as the reference case, the NPV costs and differentials in Table 7.1 were calculated:

Table 7.1

NPV Cost in Millions of 2002 Dollars

Conditions	Portfolio 1 (VIGP)	Portfolio 2 (On-Island CCGTs)	Portfolio 3 (Mainland CCGTs)	Portfolio 2-Portfolio 1	Portfolio 3-Portfolio 1
Application	9,677	9,525	9,687	-152	10
High Gas Price	11,528	11,353	11,564	-175	36
6% Real Discount Rate	14,387	14,181	14,401	-206	14
6.5% Rate Increase	7,772	7,642	7,788	-130	16

These results support VIEC s position that Portfolio 2 is the preferred portfolio. Higher gas prices favour gas-fired generation on Vancouver Island because of lower losses on GSX compared to electric transmission lines and the selection of a CCGT as the default resource for Portfolio 3. The ranking of the portfolios is not sensitive to gas prices or discount rate.

7.3.2 Portfolio 4

In response to a Commission staff Information Request, VIEC provided portfolio analysis results for a Portfolio 4 based on BC Hydro s December 2002 load forecast, as well as the load forecast that assumed a 6.5 percent annual rate increase for three years (Exhibit 4E, BCUC IR 66.1). The portfolio assumed the following incremental on-Island resources would be available:

Resource Smart -	14 MW from turbine upgrades, plus 39 MW at Strathcona and Ladore at a cost of $40.9 million in 2002 dollars.
Green Energy -	An additional 26 MW and 400 GWh/year, at a cost of $55/MWh.
Demand Management -	80 MW from NorskeCanada, at no cost.
NorskeCanada Generation -	NorskeCanada generation was added as needed, at $65/MWh (price assumed to include TGVI gas transportation costs).

Assuming that no reinforcement of on-Island transmission is needed, VIEC calculated the NPV costs shown in Table 7.2 for Portfolio 4:

Table 7.2

NPV Cost in Millions of 2002 Dollars

December 2002 Load Forecast	$9,707 million ($30 million higher than Portfolio 1)
Rate Increase 6.5 percent	$7,768 million ($4 million less than Portfolio 1)

Although the Resource Smart projects at Strathcona and Ladore add costs, the higher NPV cost for the December 2002 load forecast is somewhat surprising, considering the 80 MW of free capacity in the form of load curtailment, and prices for Green Energy and NorskeCanada generation that are equal to or less than the cost of power from VIGP. The results may simply indicate that the portfolio analysis is unable to distinguish between Portfolios 1 and 4. VIEC stated that NPV differences in the tens of millions of dollars are not significant, while a difference of $152 million is a material difference (T5: 1097). Nevertheless, the results for Portfolio 4 raise questions about the usefulness of the portfolio analysis model for comparing resource alternatives submitted under the CFT.

7.3.3 Effect of Capital Structure and Capital Charges

In response to an Information Request, VIEC also provided portfolio analysis results for VIGP for two capital cost scenarios (Exhibit 4E, BCUC IR 64.2). Using the P90 rather than the P50 capital cost estimate increased the NPV cost of Portfolio 1 by $24 million. As VIEC noted, this reflects the $30 million difference between the P50 and P90 cost estimates.

The second capital cost scenario used the P90 cost estimate, and also assumed a 50/50 debt/equity ratio, 7 percent debt cost and 12 percent after tax return on equity. VIEC calculated that these assumptions would require annual payments for the facility of $53 million in nominal dollars or $42 million in real levelized 2002 dollars. This scenario had a NPV cost that was $98 million higher than Portfolio 1 ($74 million higher than the other scenario that was based on the P90 cost estimate).

These results illustrate the effect that assumptions about capital structure and capital charges can have on the results of the portfolio analysis. The model treats BC Hydro investments on a cash flow basis, which is not intended to accurately represent the effect on utility revenue requirements and customer rates. The capital charges used as inputs to the cost of service analysis and the CFT Benchmark set forth in Chapter 9 should be consistent with BC Hydro s overall equity return as set out by Special Directive Number 4 and Special Direction Number 8, as determined in Section 5.5.

7.3.4 Portfolio Analysis Updates

During the hearing, VIEC revised the portfolio analysis for updates to gas and electricity prices, GSX costs, TGVI costs, VIGP costs and sunk costs (Exhibit 4FF). VIEC also provided results for Portfolios 13, 11 and 14 which correspond to Portfolios 1, 2 and 3 with VIGP and GSX sunk costs removed (Exhibit 4AAA). When VIEC removed the sunk costs, it left the Perpetuity Adjustments unchanged to reflect the full capital cost of future replacements.

Table 7.3

NPV Costs in Millions of 2002 Dollars

Conditions	Portfolio 1 (or 13) (VIGP)	Portfolio 2 (or 11) (On-Island CCGTs)	Portfolio 3 (or 14) (Mainland CCGTs)	Portfolio 2-Portfolio 1	Portfolio 3-Portfolio 1
Updated Costs	9,331	9,176	9,317	-155	-14
Remove Sunk Costs	9,236	9,081	9,222	-155	-14

The updated costs do not significantly change the ranking of the portfolios. Removal of VIGP and GSX sunk costs from all portfolios does not affect the NPV cost differentials between the portfolios.

In response to a request during the hearing, VIGP also provided results for Portfolios 12 and 12A (Exhibit 4AAA). Portfolio 12 modifies Portfolio 2 by removing the VIGP sunk costs of $46 million NPV. Portfolio 12 also incorporated a TGVI on-Island toll of $0.60/GJ, which increased the Gas Transportation Cost by $203 million NPV. The resulting total NPV costs for Portfolio 12 is $9,333 million.

Portfolio 12A is the same as Portfolio 12, except that GSX sunk costs were removed as well as VIGP sunk costs. The resulting total NPV cost for Portfolio 12A is $9,283 million. Excluding all sunk costs and including the TGVI on-Island toll yields a total NPV cost for the on-Island multiple CCGT scenario that is $61 million higher than the cost for the corresponding Mainland generation/230 kV line scenario without sunk costs that is represented by Portfolio 14.

7.3.5 Accuracy of Portfolio Analysis Results

In response to a request from NorskeCanada, VIEC provided information about the accuracy of portfolio analysis results recognizing the very large absolute NPV costs generated by the analysis (Exhibit 4QQQ). VIEC states that, because of the common elements among the portfolios, comparing the differences in NPV costs between portfolios to the absolute or total NPV costs is meaningless. However, it considers that this does not detract from the appropriateness or application of the NPV methodology.

VIEC considers that what is important is that the elements that should be constant have been kept constant, and that specific variables have been tested for sensitivity. VIEC states that it carefully designs and checks the portfolios to avoid inconsistencies and unintended cost differences between portfolios, to ensure that the common elements are exactly the same in each portfolio.

VIEC evaluated the sensitivity of the portfolio analysis to uncertainty in capital cost estimates and to the timing of a 230 kV transmission line to Vancouver Island under Portfolio 2. Table 7.4 is a summary of the NPV costs and cost differentials from Exhibits 4AAA and 4QQQ:

Table 7.4

NPV Costs in Millions of 2002 Dollars

Conditions	Portfolio 13 (Portfolio 1 w/o VIGP & GSX sunk costs)	Portfolio 11 (Portfolio 2 w/o VIGP & GSX sunk costs)	Portfolio 14 (Portfolio 3 w/o VIGP & GSX sunk costs)	Portfolio 11 -Portfolio 13	Portfolio 14 -Portfolio 13
Results using updated costs	9,236	9,081	9,222	-155	-14
+25% on 230 kV line cost				-181	-8
+8% on VIGP cost				-155	-37
+10% on Revelstoke Unit 5 cost				-155	-12
+25% on Interior-ML Trans cost				-157	-12
+25% on Mainland CCGT cost				-155	+29
Portfolio 2, 230 kV line in 2021				-105	-14
Portfolio 2, 230 kV line in 2010				-47	-14

Based on the foregoing analysis, VIEC concluded that Portfolio 2 (or Portfolio 11) is the least-cost portfolio, and that the NPV differences between Portfolios 1 and 3 (or Portfolios 13 and 14) are not significant.

The NPV cost of $9,222 million for Portfolio 14 includes $245 million of incremental TGVI gas transportation costs. If the incremental TGVI gas transportation costs are removed in order to be consistent with the determinations in Chapter 5, then Portfolio 14 is $104 million less expensive than Portfolio 11 and $259 million less than Portfolio 13. This is a material difference in favour of Mainland generation with a new 230 kV transmission line to the Island.

The Commission Panel accepts the conclusion from the sensitivity analysis that the uncertainty in the capital cost of alternative projects is unlikely to affect the ranking of the portfolios. Installation of a 230 kV line to Vancouver Island in the near future (in addition to GSX and multiple CCGTs on the Island) would appear to largely offset the lower NPV cost of Portfolio 11 (or Portfolio 2).

In addition, the need for careful and consistent design of portfolios is a concern as the proprietary nature of the model means that the Commission Panel and others are unable to validate that this has been done properly.

7.4 VIEC Views on Portfolio Analysis

VIEC argues that Portfolio 1 meets both the needs of the BC Hydro system and the immediate constraint of reliability of supply to Vancouver Island. It defers new Vancouver Island transmission to 2010 and new Interior to Lower Mainland 500 kV transmission to 2013/14. The cost of advancing VIGP for service in 2006 is in the capital and fixed costs of that generation, including the incremental cost of firm gas transportation and fuel cost. The value of that generation is in cost savings in operating existing resources and imports for the domestic market, and the value of increased exports.

Portfolio 2 looks at the additional economic advantage that would be achieved if future gas-fired generation were added on Vancouver Island. VIEC states that it also has the lowest net present value cost of the three portfolios.

Portfolio 3 is developed assuming the Mainland generation resources would be acquired on a competitive basis and that CCGT technology represents an appropriate proxy for all such competitively-acquired generation. VIEC states that, since there is not a significant difference between Portfolio 1 and Portfolio 3, approval of VIGP does not imply a requirement to follow it with future on-Island CCGTs. However, the expected regulatory approval and construction timetable of Portfolio 3 makes it difficult to complete prior to the winter of 2007/08.

VIEC notes that, while a 6 percent real discount rate is closer to BC Hydro s current weighted average cost of capital, using an 8 percent discount rate to calculate the net present value actually imposes a more onerous test on Portfolio 1. Its sensitivity analysis indicates that changing the gas/electricity prices or the capital and fixed operating costs does not affect the ranking of the portfolios, and neither does the addition or deletion of sunk costs.

7.5 Intervenor Positions on Portfolio Analysis

Most intervenors neither supported nor opposed the portfolio analysis methodology utilized by BC Hydro. NorskeCanada argued that, if a portfolio methodology model is to be used to assess bids in a CFT, it must be available to bidders in advance in order to give all bidders a proper opportunity to design their project to best meet BC Hydro s requirements. NorskeCanada also argued that bids should be evaluated on a NPV basis rather than on the basis of levelized costs, as levelized costs are not readily understood by those outside BC Hydro.

GSXCCC argued that BC Hydro has neutralized the portfolio analysis by costing all portfolios on the basis of gas-fired generation; by ignoring the potential liability of GHG emissions; and by ignoring smaller, incremental means of meeting needs on Vancouver Island. It felt that a broader range of portfolio options should have been included. GSXCCC and other intervenors, including the JIESC, NorskeCanada and CBT, argued that Portfolio 3 was the preferable alternative.

Mr. McKechnie noted VIEC s evidence that the modelling/simulation software was developed in-house and that the model s prediction of plant utilization rate was not tested against real-life plant performance such as at Burrard or ICP (T8: 1585-90). He argued that the prediction that VIGP would run essentially full time is counterintuitive considering the load factor at Burrard and recognizing those times when hydro electricity is available from the market at lower cost. He noted the model is not transparent for checking by others, and expressed concern that small inaccuracies in the input data, for example gas prices and currency exchange rates, could affect the results.

7.6 Commission Panel Determination

The Commission Panel accepts that portfolio analysis can be a valuable tool, especially for assessing the many variables in a broad interconnected system like that of BC Hydro. However, the Commission Panel shares some of the concerns raised by intervenors with respect to the lack of transparency that exists when BC Hydro uses proprietary models to develop important decision-making tools. **In future applications, the Commission Panel expects BC Hydro to use assessment models which can be made public so that the various components and assumptions can be assessed and tested by intervenors.**

VIEC s portfolio analysis includes many variables, and there is a degree of subjectivity in terms of assessing the costs of the variables. The Commission Panel accepts that in the Application there are a myriad of inter-relationships which must be assessed, and VIEC has made its best effort to develop a model which can assess how different project options will impact the overall BC Hydro system. The following are some of the key variables which impact the portfolio analysis and the Commission Panel s concerns that relate to these variables.

- Load Forecast

  BC Hydro s forecast model calculates different responses to peak demand and energy requirements caused by an assumed rate increase because energy requirements are more elastic than peak demand. Therefore, a reduction in forecast load (regional or system-wide) should not only defer most elements in the reference case portfolio, but should also result in a re-prioritization of the supply stack to match the type of load requirement. Currently, the usefulness of VIEC s sensitivity analysis of load forecast is limited since the portfolio analysis uses a Mainland CCGT as the default resource and focuses on resource location and resource timing rather than a diversity of resources.

- New Rate Designs (General Use, TOU, Industrial Stepped Rates)

  The introduction of new rate structures will provide incentives for consumers to meet part of their electricity needs through conservation and efficiency. This may mean that it is more economical to have a direct-fired natural gas furnace in a home versus a gas-fired generator supplying electricity for space heat in a home. A new rate structure may also mean smaller incremental electricity purchases at lower prices to service the reduced incremental load growth than otherwise would be the case. These scenarios weaken VIEC s assumption that a CCGT is the proxy resource in its portfolio analysis.

- Discount Rate

  Whereas the 8 percent real discount rate used by VIEC may impose a more onerous test on Portfolio 1 than a 6 percent real discount rate, Portfolio 1 also includes GSX costs which may or may not face the same level of risk as the TGVI upgrades in Portfolio 3. Similarly IPPs investing in future CCGTs will have different costs of capital and different levels of risk tolerance attached to their investment costs.

- Mainland CCGT as the Default Resource

  The analysis used a gas-fired CCGT at Kelly Lake as the default resource, and did not consider other non-gas options such as wood waste, hydropower or coal. Gas-fired generation may or may not be BC Hydro s most likely resource addition in the near future. In any case, the absence of a scenario based on non-gas-fired resources seriously limited the usefulness of the gas price sensitivity analysis.

- Capital and Operating Costs

Facility cost estimates have uncertainties that may compound as well as offset each other (e.g., the estimated cost of VIGP may overstate the actual costs, while the estimate for transmission additions may understate the actual cost). This can lead to inaccuracies in the differential between the NPV costs for the corresponding portfolios.

- Gas and Electricity Prices

The gas and electricity prices that are input into and calculated within the model may not accurately represent future prices or the relationship between gas and electricity prices. The model relies on the assumption that gas-fired CCGTs will largely determine electricity prices, and this could affect the calculated utilization rates and bias the comparison of alternatives.

- Maximum Electricity Purchases

BC Hydro argues that its reliability planning limit of 2,500 GWh per year for market purchases limits its exposure to high import costs during periods of low stream-flow conditions. Nevertheless, this is an arbitrary constraint that may increase the indicated need for on-system resources.

- Perpetuity Adjustments

Perpetuity Adjustments are a significant portion of the total NPV cost, typically about one-third. The capital cost and project life are significant assumptions used in the calculation, and uncertainty in these assumptions would affect the accuracy of the adjustments.

- Treatment of Expansions of Other Utility Systems

The portfolio analysis included the incremental revenue requirements of all expansions of facilities to deliver gas to Vancouver Island, including facilities to meet anticipated growth in gas demand on the Island. The analysis should be limited to BC Hydro costs, specifically incremental costs that BC Hydro will pay for gas transportation to the Island.

The Commission Panel considers that the results of the portfolio analysis are not conclusive. While many of the scenarios favour VIGP and the development of gas generation on Vancouver Island, other scenarios support a new transmission line to the Island. The Commission Panel is particularly concerned with respect to the assumption that a CCGT located near Kelly Lake is representative of the competitive cost of additional resources on the Mainland. In the current natural gas price environment, BC Hydro may have many other resource options available at lower cost than a CCGT on the Mainland. Also, the Commission Panel has not received sufficient information with respect to the expected growth in consumption on the Mainland to verify the timing of resource additions required for system-wide loads.

8.0 COMMISSION DECISION

8.1 The Test of Public Convenience and Necessity

The Application was submitted pursuant to Sections 45 and 46 of the Utilities Commission Act. Sections 45 and 46 of the Act provide as follows:

> 45 (1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.
>
> (2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it
>
> (a) to operate the plant or system, and
>
> (b) subject to subsection (5), to construct and operate extensions to the plant or system.
>
> (3) Nothing in subsection (2) authorizes the construction or operation of an extension that is a reviewable project under the Environmental Assessment Act.
>
> (4) The commission may, by regulation, exclude utility plant or categories of utility plant from the operation of subsection (1).
>
> (5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.
>
> (6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.
>
> (6.1) A public utility must file the following plans with the commission in the form and at the times required by the commission:
>
> (a) a plan of the capital expenditures the public utility anticipates making over the period specified by the commission;
>
> (b) a plan of how the public utility intends to meet the demand for energy by acquiring energy from other persons, and the expenditures required for that purpose;

(c) a plan of how the public utility intends to reduce the demand for energy, and the expenditures required for that purpose.

(6.2)After receipt of a plan filed under subsection (6.1), the commission may

(a) establish a process to review all or part of the plan and to consider the proposed expenditures referred to in that plan,

(b) determine that any expenditure referred to in the plan is, or is not at that time, in the interests of persons within British Columbia who receive, or who may receive, service from the public utility, and

(c) determine the manner in which any expenditures referred to in the plan can be recovered in rates.

(7) Except as otherwise provided, a privilege, concession or franchise granted to a public utility by a municipality or other public authority after September 11, 1980 is not valid unless approved by the commission.

(8) The commission must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest.

(9) In giving its approval, the commission

(a) must grant a certificate of public convenience and necessity, and

(b) may impose conditions about

(i) the duration and termination of the privilege, concession or franchise, or

(ii) construction, equipment, maintenance, rates or service, as the public convenience and interest reasonably require.

46 (1) An applicant for a certificate of public convenience and necessity must file with the commission information, material, evidence and documents that the commission prescribes.

(2) The commission has a discretion whether or not to hold any hearing on the application.

(3) The commission may issue or refuse to issue the certificate, or may issue a certificate of public convenience and necessity for the construction or operation of a part only of the proposed facility, line, plant, system or extension, or for the partial exercise only of a right or privilege, and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require.

(4) If a public utility desires to exercise a right or privilege under a consent, franchise, licence, permit, vote or other authority that it proposes to obtain but that has not, at the date of the application, been granted to it, the public utility may apply to the commission for an order preliminary to the issue of the certificate.

(5) On application under subsection (4), the commission may make an order declaring that it will, on application, under rules it specifies, issue the desired certificate, on the terms it designates in the order, after the public utility has obtained the proposed consent, franchise, licence, permit, vote or other authority.

(6) On evidence satisfactory to the commission that the consent, franchise, licence, permit, vote or other authority has been secured, the commission must issue a certificate under section 45.

(7) The commission may amend a certificate previously issued, or issue a new certificate, for the purpose of renewing, extending or consolidating a certificate previously issued.

(8) A public utility to which a certificate is, or has been, issued, or to which an exemption is, or has been, granted under section 45(4), is authorized, subject to this Act, to construct, maintain and operate the plant, system or extension authorized in the certificate or exemption.

The UCA does not define public convenience and necessity. However, the Commission Panel has been referred to several court cases which discuss the phrase. In the case of *Memorial Gardens v. Colwood*

Cemetary (sub nom *Colwood Cemetary v. Public Utilities Commission),* [1958] SCR 353, 13 D.L.R. (2d) 97 (S.C.C.) at D.L.R. 101 Abbott J. states the following:

> As the Court held in the *Union Gas* case the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission.

The passage was considered at paragraph 48 of the *BC Hydro Court of Appeal* case in reference to the certification process under the UCA.

In the *Memorial Gardens* case, the Court also commented that it would be both impracticable and undesirable to attempt a precise definition of general application of what constitutes public convenience and necessity and that a meaning in a given case should be ascertained by reference to the context and to the objects and purposes of the statute in which it is found. (*Memorial Gardens* at pp. 100, 101) Accordingly, the test of what constitutes public convenience and necessity is a flexible test. As stated at page 2 of the Final Argument of CBT in referring to *Interstate Commerce Commission v. Parker, 326 U.S. 60(1945), at p. 65* the Commission may 'draw its conclusion from the infinite variety of circumstances which may occur in specific instances'.

VIEC framed the Application on the basis that VIGP is the most cost-effective means to reliably meet Island power needs (Exhibit 1, p. 1). That wording is also found in Energy Plan Policy Action #6. In discussing the Commission s task under Section 45 at paragraph 11 of its Final Argument, VIEC submitted:

> Therefore, to carry out its task under s. 45, the Commission must formulate an opinion on the need and desirability of locating new electric generation on Vancouver Island-in particular, the need for the VIGP-as well as considering the cost effectiveness of the proposed means of meeting that need. It is in this context that the evidence on the nature of the Island's electricity demand/supply balance and the condition and reliability of the transmission interconnections to the Island is important, as discussed in this submission.

The Application was filed as a consequence of Policy Action #6. While the Energy Plan does not pre-empt the Commission's jurisdiction under Sections 45 and 46 of the Act, the Commission Panel is of the view that whether or not VIGP is the most cost-effective means to reliably meet Island power needs is a factual matter that the Commission Panel can take into account in arriving at its Decision on whether to grant VIEC a CPCN.

During written and oral argument, parties sometimes referred to a least-cost test and at other times referred to a most cost-effective test. It appeared that the tests were being used interchangeably at times (T14:°3016, 3017, 3022, 3023, 3030-3034).

VIEC s position was stated as follows:

> The touchstone is to issue a CPCN, the Commission must be satisfied that this is the most cost effective way to reliably meet the needs. (T14: 3017)

The principal distinction between most cost-effective and least-cost is the scope of considerations that are relevant. In the context of this Decision, most cost-effective includes consideration of project characteristics such as reliability, dispatchability, timing, and location as well as the cost or price, in the case of an EPA. Least-cost is taken to only include cost or price considerations.

TGVI submitted that the test was whether or not a project meets the public convenience and necessity and that it was incorrect to say that the test was least-cost or most cost-effective (T14: 3041). The Commission Panel must discharge its responsibilities under Sections 45 and 46 of the Act and concludes that Policy Action #6 is compatible with the test of whether the project is necessary for the public convenience and necessity, and properly conserves the public interest. VIEC must demonstrate that VIGP is the most cost-effective project to meet the needs of the ratepayers of BC Hydro. Safety, reliability and other impacts are relevant factors, along with the cost to ratepayers and the impact on the financial capability of the utility.

Based on the evidence and the Commission Panel conclusions in this Decision, the Commission Panel finds that VIEC has not established that VIGP is the most cost-effective means to reliably meet Vancouver Island power needs. Therefore, the Commission Panel denies the Application for a CPCN.

On the subject of the need for further study and analysis and the risk of failing to secure essential supply, Mr. Mansour of the British Columbia Transmission Corporation gave the following evidence:

> I feel that we have done enough studying, enough analyzing, we are compromising enough, and really enough is enough, in taking the risk of failing to secure essential supply to that region and to our customers. (T4: 778)

The Commission Panel encourages BC Hydro to proceed with a CFT on the schedule set forth in Schedule A in VIEC s Reply Argument at pages 45 and 46. Based on the results of the CFT, the Commission is prepared to consider any future application for CPCN approval or Electricity Purchase Agreement approval on an expedited basis.

8.2 Scope of Economic Analysis

In its Final Argument, VIEC submitted that the Commission Panel should not be concerned with achieving equity among competing private interests or even among competing public utilities. It submitted that the concern, in the case of a distribution utility, is maximizing the best interest of its ratepayers (VIEC Final Argument, paragraphs 12-14). VIEC provided court cases to support its position.

The issue was canvassed by the Commission Panel in the oral argument phase of the hearing. GSXCCC submitted that the Commission Panel, as a matter of law, was not constrained to looking only at the impacts on BC Hydro ratepayers (T14: 3008, 3009). Most other counsel took the position that the Commission Panel could look at impacts on parties who were not BC Hydro ratepayers, but that it should exercise caution in so doing. Counsel for TGVI expressed the view that the Commission Panel should look primarily at the cost to BC Hydro's customers but should not ignore the effect on other utilities completely.

The Commission Panel agrees with VIEC that it is not concerned with achieving equity among competing private interests or even among competing utilities in its determination of the Application. In this Decision, the responsibility of the Commission Panel is to consider whether VIGP is the best resource addition for the needs of BC Hydro s customers.

9.0 CALL FOR TENDERS

9.1 Introduction

In Chapter 4, the Commission Panel confirmed that there will be a future capacity shortfall on Vancouver Island. Although the Commission Panel has found that the need for new supply resources is approximately 100 MW less than BC Hydro s forecast for 2007/08, there is a need to move expeditiously to reinforce electricity supply to Vancouver Island prior to the winter of 2007/08. The evidence in this hearing suggests that the appropriate next resource addition should be on-Island generation, provided the costs of the proponents projects can be confirmed near their expected values.

BC Hydro recognizes that it has the responsibility to ensure reliable supply at reasonable cost to all its customers, and the Utility has been pro-active in addressing the Vancouver Island problem since the mid-1990s. The denial of a CPCN for VIGP is a result of the Commission Panel being unable to find that VIGP is the most cost-effective solution to the problem at hand. The future reliability concerns remain and the

Commission Panel expects BC Hydro to reapply for a CPCN or EPA approval by spring 2004 to resolve these concerns.

During the hearing BC Hydro developed its proposal for a CFT (including sale of the VIGP), as evidenced in Exhibit 4KK and Exhibit 4QQ, and at pages 39 to 46 in the ViEC Reply Argument, Schedule A: Call for Tenders (Schedule A). BC Hydro s efforts to prepare the CFT documents during the hearing are commendable. Generally, BC Hydro made a significant effort during this proceeding to be responsive to questions and requests. It is the Commission Panel s impression that bidders into the CFT can anticipate a fair and transparent process, especially given BC Hydro s willingness to engage an Independent Reviewer and the Commission s eventual review of a CPCN application or EPA filing.

This Chapter includes suggestions for the CFT process, since the Commission Panel accepts that a utility has the initial responsibility to plan for its future resource additions. The Commission Panel acknowledges the submission of VIEC that, in the absence of a CPCN approval, BC Hydro is in a much more difficult situation and may not proceed with the CFT (T14: 3098). It will be BC Hydro s choice whether to proceed with the CFT recognizing that BC Hydro must develop sufficient information to identify the most cost-effective resource addition for Vancouver Island. The results of the CFT would provide valuable information for BC Hydro to discharge its responsibility. The Commission Panel encourages BC Hydro to proceed with the CFT and to closely follow the schedule set forth in Schedule A. It is the Commission Panel s hope that the information in BC Hydro s future filing, coupled with the extensive review undertaken in this proceeding, will allow the Commission to approve the preferred resource addition without a second oral hearing.

This Decision neither proposes changes to, nor endorses, Schedule A. Schedule A, at Section 11, states:

> It is BC Hydro s intent to design and execute a process consistent with this document. However, this document is a summary, prepared before the CFT process detailed design is complete. Accordingly, BC Hydro may vary this document with the approval of the BCUC and with notice to intervenors, in the course of finalizing the design and execution of the process.

The Commission Panel accepts that variations to Schedule A may be necessary. The following comments are therefore intended only as considerations for the design and execution of the process.

9.2 Resource Plan

BC Hydro stated that it will be preparing a resource plan later this year (T1: 80). Commission staff are seeking comments on Resource Plan guidelines and both BC Hydro and the British Columbia Transmission

Corporation have responded with helpful comments. The Commission intends to circulate the approved guidelines by October 2003. The Commission Panel expects that the CFT will be distinct and separate from the Resource Plan process and the Resource Plan guidelines, because of the ongoing nature of planning and project development for supply to Vancouver Island. For future applications a Resource Plan may provide essential support for project approval but, given the evidence filed in this proceeding which may be complemented with the CFT, the selected project need not be supported by a Resource Plan.

9.3 Conflict - Buyer and Proponent

In Final Argument at page 15, NorskeCanada states:

> How the Commission decides to handle the obvious conflict BC Hydro faces in its roles as buyer and proponent will probably be the biggest single influence on IPPs who are considering whether to participate in the CFT.

The paramount concern of many of the intervenors was the role of BC Hydro as a proponent of a project and as the selector of the preferred project (Arguments of Green Island, p. 6; JIESC, p. 3; TGVI, p. 25; BCOAPO, p. 22 and SPEC, p. 5). BC Hydro has designed Schedule A to address this concern. However, some intervenors are not convinced that any mechanism short of eliminating BC Hydro s role as a proponent of a generation project will be adequate. NorskeCanada prefers that the Application be denied rather than firmly establishing the Commission s jurisdiction in the CFT process.

For this CFT, BC Hydro is unavoidably in the position of being a project proponent and the selector of the preferred project. The Commission Panel does not expect BC Hydro to eliminate its role as a proponent of VIGP and GSX in the CFT. However, the Commission Panel does encourage BC Hydro to select an Independent Reviewer as set forth in Schedule A, Section 7.1, and have the Independent Reviewer report to a Commissioner, who will then not sit on the Commission panel that may be required to hear an application for approval of the selected resource addition.

9.4 Cost Comparison Benchmark and Methodology

Section 1.2 of Schedule A states:

> The preferred option will be determined by comparing the preferred tenders or suite of tenders with the BC Hydro build-own-operate option to which the CPCN is applicable and evaluating options in accordance with BC Hydro s net present value portfolio analysis.

Section 6.2 of Schedule A states:

> Tenders or tender suites will be evaluated in accordance with BC Hydro s net present value portfolio analysis in a manner consistent with the CPCN application. The evaluation will determine the relative cost-effectiveness and reliability of each tender and/or portfolio relative to BC Hydro s obligation to serve load on a system-wide basis.

Chapter 7 of this Decision discusses the strengths and limitations of BC Hydro s portfolio analysis. The Commission Panel has also addressed the concerns of some intervenors that the model is a black box which is not sufficiently transparent to allow examination and verification. However, given the Commission Panel s determination that the logical next resource addition is on-Island generation, it should be possible to develop a simplified NPV model specifically for the CFT. The NPV model should be available to bidders in advance and the Commission Panel believes it could be limited to on-Island generation costs, without the need to consider future impacts to electricity transmission or generation on the Mainland.

The CFT Benchmark should be VIGP with GSX. In Chapter 5, the Commission Panel recognized that there remains considerable uncertainty in the costs of VIGP, and developed two plausible scenarios to cover the likely range of the cost of electricity from VIGP. For a CFT Benchmark that is consistent with the likely range of VIEC costs for VIGP and provides a valid comparison for generation projects advanced by other proponents, the Commission Panel suggests that BC Hydro calculate the CFT Benchmark based on the following inputs to the NPV model used for the CFT:

- Utilization rate - 77.5 percent;
- GSX costs - 50 percent of updated GSX toll, without adjustment for GSX sunk costs;
- TGVI charges - $0.60/GJ on-Island toll;
- Gas commodity costs - annual average of BC Hydro s reference and high forecast gas prices;
- Motor fuel tax - 7 percent of gas commodity cost;
- Greenhouse gas costs - $3.60/MWh in real 2002 dollars;
- Capital cost - average of the P50 and P90 estimates, less VIGP sunk cost;
- Capital structure - 80/20 debt/equity ratio;
- Debt interest rate - BC Hydro s current cost of long-term debt;
- Return on equity - based on Special Direction Number 8; and
- OMA costs - VIEC estimate.

The Commission Panel accepts the position of most intervenors that sunk costs are not relevant to this project selection decision and should not be used in the NPV analysis, either as an addition to IPP project costs or included in the CFT Benchmark.

The CFT Benchmark inputs are being suggested by the Commission Panel only for the purpose of the CFT. A future Commission review of VIGP and GSX costs may result in findings that are different from those suggested by the proposed inputs for the CFT Benchmark.

9.5 Gas Transportation

TGVI stated that it was not necessary as part of this proceeding to determine whether or not GSX was more cost-effective than an expansion of the TGVI system. BC Hydro advocates the use of VIGP with GSX for the CFT Benchmark. Therefore, the Commission Panel has not made a determination of the relative costs of GSX transportation as compared to TGVI transportation.

For the purposes of the CFT, the Commission Panel encourages BC Hydro to accept long-term transportation service from TGVI equally as well as it would be prepared to accept a proposal using GSX transportation. If BC Hydro proceeds with the CFT, it should ensure that there is good evidence for all gas transportation alternatives to GSX so that such alternatives can be fairly evaluated.

9.6 Environmental Assessment Certificate

VIEC anticipates receiving its Environmental Assessment Certificate shortly after the issuance of this Decision. Any project modifications required by the Environmental Assessment Certificate should be included in the CFT Benchmark analysis for VIGP.

9.7 Rejection of Tenders

Section 10 of Schedule A states:

> BC Hydro may reject all tenders if the acceptable aggregate Dependable Capacity is less than 240 MW.

NorskeCanada at page 15 of its Final Argument states: There must be an assurance that the best combination of bids under the CFT Benchmark, up to the limits of the CFT, will be selected.

The Commission Panel anticipates that the sum of the viable tenders will provide BC Hydro with an aggregate Dependable Capacity of at least 150 MW, which would provide a buffer above the 116 MW required in 2007/08. The Commission Panel encourages BC Hydro to seek approval for projects with an aggregate capacity of at least 150 MW as long as each project is cost-effective, and the aggregate capacity is required to meet Vancouver Island and system load requirements. If the Dependable Capacity does not exceed 115 MW, then the Commission Panel expects that BC Hydro will need to consider other resource additions, including VIGP/GSX, CBG, Resource Smart, contracted load reductions and new peak shaving initiatives, for meeting the load requirements as set forth in Chapter 2.

9.8 Sale of VIGP to IPP - Price of Assets

As a public utility under the UCA, BC Hydro has an obligation to serve its customers. Under the Energy Plan, the obligation to serve will functionally fall to BC Hydro Distribution. Further, new generation resources are to be built by the private sector unless BC Hydro receives Cabinet approval to construct a new hydroelectric facility (Policy Action #13). In this regard, VIGP may be considered a transition project (T2: 434). This was reinforced by the letter from the Minister of Energy and Mines that was filed during the hearing (Exhibit 4XX).

At the commencement of the hearing, BC Hydro initially stated that it had no proposals to sell VIGP and GSX (T1:68). During the hearing, Exhibit 4XX was filed and BC Hydro has indicated that the CFT will include a call for the sale of VIGP (VIEC Argument, p. 7). Section 2.6 of Schedule A permits bidders in the CFT to tender for the acquisition of the existing VIGP assets. The Commission Panel encourages BC Hydro to divest VIGP and GSX, as long as it makes economic and financial sense to do so. As stated earlier, the Commission is prepared to consider any future application for approval of VIGP or other cost-effective resource on an expedited basis.

9.9 Conclusion

The implementation of the Energy Plan will require BC Hydro to make capacity calls from time to time as necessary to meet load requirements. If BC Hydro proceeds with the CFT, the Commission Panel is of the understanding that this will be its first capacity call.

The Commission Panel believes that it is important that the CFT be perceived as fair and open so that projects other than VIGP with GSX supply compete on a level playing field to meet the load requirements of Vancouver Island. The success of the CFT is also important to the enhancement of goodwill that may benefit future resource calls.

Dated at the City of Vancouver, in the Province of British Columbia, this 8th day of September 2003.

Original signed by:
Robert H. Hobbs
Chair

Original signed by:
Nadine F. Nicholls
Commissioner

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-55-03

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by Vancouver Island Energy Corporation
(a Wholly-Owned Subsidiary of British Columbia Hydro and Power Authority)
for a Certificate of Public Convenience and Necessity for the Vancouver Island Generation Project

BEFORE:	R.H. Hobbs, Chair	)	
	N.F. Nicholls, Commissioner	)	September 8, 2003

O R D E R

WHEREAS:

A. On March 12, 2003, Vancouver Island Energy Corporation (VIEC) applied pursuant to Sections 45 and 46 of the Utilities Commission Act (the Act) for a Certificate of Public Convenience and Necessity (CPCN) for the Vancouver Island Generation Project (VIGP) (the Application); and

B. VIEC is a wholly-owned subsidiary of British Columbia Hydro and Power Authority (BC Hydro). The Application stated that VIGP is BC Hydro s preferred option for securing reliable electricity supply for Vancouver Island and the Gulf Islands; and

C. VIGP is comprised of a combined-cycle natural gas turbine power generating plant at Duke Point near Nanaimo, a connection and upgrade to the existing transmission grid, a short gas supply pipeline and related works. The Application stated that VIGP would provide 265 megawatts of power, has an estimated cost of $340 million, and has an expected in-service date of July 2006; and

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D. The environmental, economic, social, heritage and health effects of VIGP have undergone an assessment by the Environmental Assessment Office. VIEC expects that its application for an Environmental Assessment Certificate will be referred to Ministers within fifteen days of the Commission Panel s Decision on the Application; and

E. VIGP is associated with the Georgia Strait Crossing Project (GSX Project), a proposed international natural gas pipeline from Washington State to Vancouver Island. The Canadian portion of the GSX Project has been reviewed by a joint panel of the National Energy Board and the Canadian Environmental Assessment Agency, who found that the GSX Project is not likely to have significant adverse environmental effects and recommended the project proceed to regulatory consideration; and

F. The Commission, by Order No. G-21-03 dated March 20, 2003, established a Regulatory Agenda and Timetable for two Workshops and a Pre-hearing Conference regarding the Application; and

G. The Commission Workshops and the Pre-hearing Conference were held on April 22 and 23, 2003 in Nanaimo, B.C.; and

H. The Commission, by Order No. G-30-03 dated April 30, 2003, established a Regulatory Agenda and Timetable for an oral public hearing commencing June 16, 2003 in Nanaimo, B.C.; and

I. On May 28, 2003, the Commission sent out a Procedural Information Letter dated May 27, 2003 and a Revised and Updated Issues List for the oral public hearing; and

J. The oral public hearing took place from June 16 to July 3, 2003 in Nanaimo and Vancouver, B.C.; and

K. During the proceeding several Intervenors identified other projects to generate electricity on Vancouver Island. Terasen Gas (Vancouver Island) Inc. submitted an alternative to the GSX Project that would expand its existing natural gas pipeline system to and on Vancouver Island to transport gas to VIGP and other gas-fired generation; and

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L. During the oral public hearing VIEC proposed that in the event the Commission was unable to grant an unconditional CPCN for VIGP, a conditional CPCN be provided. The conditional CPCN would require BC Hydro to undertake a Call for Tenders to determine if there are other more cost-effective projects to meet its obligation to serve Vancouver Island with reliable and timely electricity supply; and

M. Written Final Arguments and Reply Argument were completed by July 25, 2003. An additional oral proceeding day was held on July 28, 2003 so that counsel could respond to specific issues identified by the Commission Panel; and

N. The Commission Panel has considered the Application, the written evidence filed prior to the hearing, the evidence presented at the hearing, the Letters of Comment that were filed and the written and oral arguments that were submitted.

NOW THEREFORE, pursuant to Sections 45 and 46 of the Act, the Commission orders that the March 12, 2003 Application by VIEC for a CPCN for the Vancouver Island Generation Project is denied for the reasons set out in the Decision that is issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 8th day of September 2003.

BY ORDER

Original signed by:

Robert H. Hobbs
Chair

VIGP Cost of Service - Lower Cost Scenario

Based on Capital Cost of $289 Million 2002 Dollars, 80 Percent Utilization, B.C. Hydro Reference Gas Prices

(Millions of Nominal Dollars)

VIGP Cost of Service	Reference	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17	2017/18
Capital Charges	Section 5.5	21	28	28	28	28	28	28	28	28	28	28	28
OMA Costs	Section 5.6	13	17	17	18	17	18	18	18	19	19	19	20
Gas Commodity	Section 5.7	62	85	85	78	72	65	66	68	69	71	72	74
Motor Fuel Tax	7% Gas Cost	4	6	6	5	5	5	5	5	5	5	5	5
Gas Transport, GSX	Section 5.9	33	23	23	23	23	24	24	24	24	24	24	24
Gas Transport, TGVI	Section 5.9	8	10	10	10	10	10	10	10	10	10	10	10
GHG Cost	Section 5.10	6	8	8	8	8	8	8	8	9	9	9	9
Total Cost of Service		**147**	**177**	**177**	**170**	**163**	**158**	**159**	**161**	**164**	**166**	**167**	**170**
Annual Energy, GWh	Section 5.8	1,393	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857
Cost per MWh	Nominal$/MWh	105.3	95.1	95.3	91.7	87.5	84.8	85.8	86.7	88.1	89.1	90.1	91.7
Cost per MWh (real)	**2002$/MWh**	**95.4**	**84.5**	**82.9**	**78.3**	**73.2**	**69.6**	**69.0**	**68.4**	**68.1**	**67.5**	**67.0**	**66.8**
Average Cost	**2002$/MWh**	**68.7**											

Commission Staff
2003/09/04

VIGP Cost of Service - Lower Cost Scenario

2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
28	28	28	28	28	28	28	28	28	28	28	28	28	7
20	21	21	22	22	22	23	23	24	24	25	25	26	7
76	77	79	81	82	84	86	88	89	91	93	95	97	25
5	5	6	6	6	6	6	6	6	6	7	7	7	2
24	24	25	25	25	25	25	25	25	25	25	25	25	6
10	10	10	10	10	10	10	10	10	10	10	10	10	2
9	10	10	10	10	10	11	11	11	11	11	12	12	3
172	**175**	**178**	**181**	**183**	**185**	**188**	**190**	**194**	**196**	**199**	**201**	**204**	**51**
1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	1,857	464
92.8	94.4	96.0	97.6	98.8	99.8	101.4	102.5	104.2	105.3	107.1	108.2	110.0	110.7
66.3	**66.1**	**65.9**	**65.7**	**65.2**	**64.6**	**64.3**	**63.7**	**63.5**	**63.0**	**62.7**	**62.2**	**61.9**	**61.1**

VIGP Cost of Service - Higher Cost Scenario

Based on Capital Cost of $319 Million 2002 Dollars, 75 Percent Utilization, BC Hydro High Case Gas Prices

(Millions of Nominal Dollars)

VIGP Cost of Service	Reference	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013/14	2014/15	2015/16	2016/17
Capital Charges	Section 5.5	24	32	32	32	32	32	32	32	32	32	32
OMA Costs	Section 5.6	13	17	17	18	17	18	18	18	19	19	19
Gas Commodity	Section 5.7	67	80	82	86	90	94	98	99	105	110	117
Motor Fuel Tax	7% Gas Cost	5	6	6	6	6	7	7	7	7	8	8
Gas Transport, GSX	Section 5.9	66	46	46	46	46	48	48	48	48	48	48
Gas Transport, Net TGVI	Section 5.9	0	0	0	0	0	0	0	0	0	0	0
GHG Cost	Section 5.10	5	7	7	7	7	8	8	8	8	8	8
Total Cost of Service		**180**	**187**	**190**	**196**	**199**	**207**	**210**	**212**	**220**	**225**	**233**
Annual Energy, GWh	Section 5.8	1,306	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741
Cost per MWh	Nominal$/MWh	137.5	107.5	109.2	112.4	114.4	118.7	120.8	121.9	126.1	129.4	133.8
Cost per MWh (real)	**2002$/MWh**	**124.5**	**95.5**	**95.1**	**95.9**	**95.7**	**97.4**	**97.2**	**96.1**	**97.5**	**98.1**	**99.4**
Average Cost	**2002$/MWh**	**102.7**										

Commission Staff
2003/09/04

VIGP Cost of Service - Higher Cost Scenario

2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32
32	32	32	32	32	32	32	32	32	32	32	32	32	32	8
20	20	21	21	22	22	22	23	23	24	24	25	25	26	7
126	133	138	153	157	160	163	166	169	173	176	180	183	187	48
9	9	10	11	11	11	11	12	12	12	12	13	13	13	3
48	48	48	50	50	50	50	50	50	50	50	50	50	50	12
0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	9	9	9	9	9	10	10	10	10	10	11	11	11	3
243	**251**	**258**	**275**	**281**	**284**	**288**	**293**	**296**	**301**	**305**	**310**	**314**	**319**	**81**
1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	1,741	435
139.7	144.3	147.9	158.2	161.3	163.3	165.4	168.1	170.2	173.0	175.2	178.1	180.4	183.4	185.8
101.8	**103.1**	**103.6**	**108.6**	**108.5**	**107.7**	**107.0**	**106.6**	**105.8**	**105.4**	**104.7**	**104.3**	**103.6**	**103.3**	**102.6**

Vancouver Island Energy Corporation
Application for a Certificate of Public Convenience and Necessity
for the Vancouver Island Generation Project

APPEARANCES

G.A. FULTON H. CRAIG	British Columbia Utilities Commission, Counsel
B.J. WALLACE, Q.C. J. KLEEFELD M. CLEMENS, Q.C.	Vancouver Island Energy Corporation (British Columbia Hydro and Power Authority)
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S. BRUNSDON	Hillsborough Resources Limited
H. ELLIS	Green Island Energy Ltd.
D. MORROW	Epcor Power Development Corp.
P.J. LANDRY	CBT Energy Inc.
J.D.V. NEWLANDS	Elk Valley Coal Corporation
W. ANDREWS T. HACKNEY	GSX Concerned Citizens Coalition and Nanaimo Citizens Organizing Committee
S. MILLER	Shadybrook Farm
M. MCLENNAN	Self
A. CALDICOTT	Self
A.D. FISHER	Self
V. VILLENEUVE	Self
M. DOHERTY	British Columbia Old Age Pensioners Organization, Council of Senior Citizens Organizations, federated anti-poverty groups of BC, Senior Citizens Association, of BC, End Legislated Poverty, West End Seniors Network, Tenants Rights Action Coalition (British Columbia Old Age Pensioners Organization *et al*)

APPEARANCES
(cont d)

D. BROWN	Society Promoting Environmental Conservation
D. FOLEY	David Suzuki Foundation
R. MCKECHNIE	Self
M. ROSE	Self
J. CAMPBELL	Self
D. POTTS C. BOIS	Joint Industry Electricity Steering Committee
R. MCLAUGHLIN	British Columbia Ministry of Energy and Mines
R. CHASE	Self

W.J. GRANT J.B. WILLISTON R.W. RERIE E. CHENG B. McKINLAY	Commission Staff
ALLWEST COURT REPORTERS LTD.	Court Reporters & Hearing Officer

Vancouver Island Energy Corporation
Application for a Certificate of Public Convenience and Necessity
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Vancouver Island Energy Corporation - Panel 3 (British Columbia Hydro and Power Authority) Mainland-to-Island Transmission System	M. BENNETT Y. MANSOUR J. MUMICK
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Joint Industry Electricity Steering Committee	S. FULTON
Norske Skog Canada Limited - Panel	D. FITZGERALD J. BEAMAN R. LINDSTROM T. STEFAN G. KISSACK
Hillsborough Resources Limited	S. BRUNDSON
Maxim Power Corporation - Panel	R. HOPP R. ERWIN
Green Island Energy Ltd. - Panel	S. EBNET G. CANAVERA P. SAGERT H. CAMPBELL

Vancouver Island Energy Corporation
Application for a Certificate of Public Convenience and Necessity
for the Vancouver Island Generation Project

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